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IN THE MATTER OF THE APPLICATION OF SOUTHWEST GAS CORPORATION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF SOUTHWEST GAS CORPORATION DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	Docket No. G-01551A-04-0876

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Marylee Diaz Cortez, William A. Rigsby and Rodney L. Moore in the above-referenced matter.

RESPECTFULLY SUBMITTED this 26th day of July, 2005.

Scott S. Wakefield
Chief Counsel

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SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

MARYLEE DIAZ CORTEZ

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Marylee Diaz Cortez. I am a Certified Public Accountant. I am the Chief of Accounting and Rates for the Residential Utility Consumer Office (RUCO) located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix I, which is attached to this testimony, describes my educational background and includes a list of the rate case and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present recommendations resulting from my review and analysis of the Southwest Gas Corporation's (Company or SWG) application for an increase in gas rates.

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's application. My recommendations are based on these analyses. Procedures performed include the formulation and analysis of data requests, the review and analysis of Staff requested data, conversations with Company personnel, as well as a review of annual reports and prior ACC decisions.

Q. What areas will you address in your testimony?

A. I will address the revenue requirement issues of rate base, operating income, and rate design. RUCO witness Rodney Moore will also address rate base and operating income issues, as well as sponsor RUCO overall revenue requirement recommendation. RUCO witness William Rigsby will address the cost of capital. Collectively, the RUCO witnesses' testimony will support RUCO's overall recommended revenue requirement.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules MDC-1 through MDC-6.

Q. Please summarize the recommendations and adjustments you address in your testimony.

A. My testimony addresses the following issues:

<u>Rate Base</u>

<u>Pipe Replacements</u> - This adjustment writes off a percentage of the cost of replacing defective pipe as required by Decision No. 58698.

<u>Miscellaneous Intangible Plant</u> - This adjustment reflects the rate base effects of the Company-proposed expired software amortizations. The

adjustment removes from rate base plant and accumulated amortization of miscellaneous intangible plant that will expire by December 31, 2004.

Working Capital - This adjustment restates SWG's cash working capital requirement based RUCO's recommended level of operating expenses and lead/lag days. The adjustment also reclassifies certain test year expenses that produce a benefit equaling or exceeding one year to the Prepayments account.

Operating Income

Sarbanes Oxley Section 404 - This adjustment trues up the Company's estimated costs of complying with Section 404 of the Sarbanes Oxley Act of 2002 to actual costs.

Transmission Integrity Management Program (TRIMP) - This adjustment restates the estimated costs of implementing and maintaining the TRIMP based actual experience during 2004 and 2005.

Amortization of Miscellaneous Intangible Plant - This adjustment reduces test year amortization expense to reflect the level of Miscellaneous Intangible Plant recommended in Rate Base Adjustment #4.

Management Incentive Plan - This adjustment removes 67% of the cost of a bonus program that awards select employees for the achievement of certain goals. In large part the benefits of achieving these goals accrue solely to shareholders, particularly between rate cases.

Demand Side Management - RUCO recommends approval of SWG proposed ramp up in DSM spending, as well as outlines a recommended design and approval process.

Rate Design

Conservation Margin Tracker - RUCO recommends that the proposed CMT be denied and that less extreme rate design tools be used to address some of the Company's concerns, as well as establish fair and reasonable rates.

Rate Structure - This section outlines RUCO recommended rate structure.

RATE BASE

Rate Base Adjustment #2 - Pipe Replacement

Q. Please provide some background regarding SWG's pipe replacement program.

A. SWG, shortly after having purchased the gas distribution properties of Tucson Gas and Electric, determined that certain types of pipe[1] used in the system were defective. This defective pipe was an issue in several SWG rate cases in the 1980s and 1990s. The most recent Commission decision that addressed the defective pipe issue was Decision No. 58693, dated July 7, 1994. The decision was based on a settlement agreement by the parties, which among other things, resolved the issue of how the defective pipe would be treated for ratemaking purposes. SWG agreed to write off a certain annual percentage of the replacement cost of the

[1] Specifically, 1960's steel pipe, and plastic pipe known as Aldyl A, Aldyl HD, and ABS.

defective pipe types. The settlement agreement also provided that the pipe replacement percentage write off amounts would decline annually until the amount reached zero.

Q. Has Southwest Gas complied with the pipe replacement write off schedule as required by Decision No. 58693?

A. Yes. Up until the instant filing SWG has continued to make the required pipe replacement write offs. In this docket, however, the Company proposes to cease making some of the write offs required by Decision No. 58693.

Q. What is the Company's rationale for not making some of the required write offs?

A. The Company is requesting that the pipe write off schedule required by Decision No. 58693 be modified so that all pipe replacement write offs would cease when the specific type of pipe reached an average life of 40 years. Under SWG's proposal, both the 1960's steel pipe and the ABS pipe would no longer be subject to write off and the scheduled write offs for the Aldyl A and Aldyl HD pipe would be modified such that write offs would cease in 2013 and 2020, respectively.

Q. Do you agree with the Company proposed modifications to its scheduled pipe replacement cost write offs?

A. Yes, I believe modification of the Decision No. 58693 write off schedule is warranted since the schedule in its current form requires continued write offs of pipe replacement costs as far out as 2068. Clearly, if pipe lasts until 2068 before having to be replaced it cannot reasonably be argued that the pipe was defective, and therefore the replacement cost should not be disallowed.

Q. Have you accepted SWG proposed pipe replacement adjustment?

A. No. While I do not disagree with the modification of the scheduled write offs on a going forward basis I do disagree with applying the modification retroactively.

Q. Has the Company proposed to retroactively modify the write off schedule dictated by Decision No. 58693?

A. Yes, the Company's proposed adjustment would apply the modified write off schedule in the current docket to its 2000, 2001, 2003, and 2004 pipe replacements.

Q. Why is this wrong?

A. During the test year (2003/2004), as well as in previous years (2000 through 2002) the Company was required to abide by the terms set forth in Decision No. 58693, which requires these write offs. While the Company certainly is free to request a change in manner in which pipe replacement write offs are handled on a going forward basis, it cannot retroactively apply that proposed methodology to previous periods. Until superceded by a subsequent Commission decision that authorizes a different treatment for pipe replacement costs the Company must abide by the terms of Decision No. 58693 in this regard.

Q. What adjustment have you made?

A. As shown on Schedule MDC-1, I have recalculated the pipe replacement write offs utilizing the methodology required in Decision No. 58693. This adjustment decreases rate base $1,982,686.

Q. Do you agree with the Company's proposed modified pipe replacement write off methodology on a going forward basis?

A. Yes. I believe the Company has a valid argument that having to write off the cost of replacing pipe that has already outlived its useful life is inappropriate. RUCO supports the Company's modified pipe replacement schedule, based on a forty-year life, as set forth on Exhibit RAM-3 and recommends it be authorized on a going forward basis.

Rate Base Adjustment #4 - Miscellaneous Intangible Plant

Q. Has the Company proposed an adjustment to account 303 - Miscellaneous Intangible Plant?

A. Yes. Account 303 consists primarily of computer software and software development costs, that have relatively short amortization periods (typically five years or less). SWG has proposed an adjustment that removes all software amortization that expired during the test year and through December 31, 2004. The proposed adjustment also annualizes the amortization associated with new software costs that went into service during the test year and through December 31, 2004.

Q. Do you agree with this adjustment?

A. Yes. The test year changes in amortization expense are known and measurable and recognition of the expired, as well as the new, amortizations gives a better reflection of a going forward level of expense. The Company, however, has failed to reflect the impact on rate base of the expiring software.

Q. Please explain.

A. SWG's proposed adjustment merely removes the amortization *expense* associated with expired assets. It fails to recognize that when amortization expires, the associated asset has been fully recovered and is no longer entitled to rate base treatment.

Q. Are you recommending an adjustment that reflects the rate base impact of the Company's proposed account 303 expired amortization adjustment?

A. Yes. On Schedule MDC-2 I have removed the book value of the expiring account 303 assets from rate base. While the Company has increased rate base by the book value of new account 303 assets it failed to reduce rate base by the expired account 303 assets. This adjustment removes the expired assets from rate base and adjusts the Company's estimated cost of the new account 303 assets to actual costs. I have also removed the accumulated amortization balance associated with the expired account 303 assets. The adjustment results in a net decrease in rate base of $845,975.

Rate Base Adjustment #6 - Working Capital

Q. Have you reviewed the Company's requested level of working capital?

A. Yes. The Company is requesting $881,148 in working capital which is comprised of a cash working capital component (based on a lead/lag study), and 13-month average balances for SWG's prepayments and materials and supplies accounts.

Q. Do you agree with the methodology the Company has used to determine its working capital requirement?

A. Yes. First, the use of 13-month average balances for prepayments and materials and supplies is preferable to year-end balances because it smoothes out any month-to-month fluctuations in these account balances. Second, use of a lead/lag study, which measures the actual time elapsed between when goods and services are provided/received and when the cash is received/paid, renders the most accurate estimate of the amount of cash the Company must have on hand to operate the business.

Q. Do you agree with the amount of working capital the Company has requested?

A. No. I disagree with some the Company's lag day calculations, and I disagree with the 13-month average balance in the prepayments account. I will be proposing adjustments related to these items. Also my working capital calculations are based on RUCO's recommended level of operating expense, and for this reason render a different level of working capital than the Company.

Q. Please discuss your recommended lead/lag day adjustments.

A. I am recommending an adjustment to the Company's Income Tax lag calculation and to its Other O&M lag calculation. SWG has calculated its Income Tax lag as 37 days. The calculation is based on the assumption that 25% of SWG's annual income tax liability must be paid quarterly on April 15, June 15, September 15, and December 15. This, in fact, is not true. The Internal Revenue Service (IRS) only requires that companies pay 22.5% of their annual income tax liability each quarter, with the final 10% due on March 15 of the year following the tax year.

Q. Does SWG take advantage of the IRS rule that allows it to pay 10% of its tax liability in the year following the tax year?

A. I am not aware of whether SWG takes advantage of the allowed lag. However, whether SWG avails itself of this opportunity or not is not germane to my recommendation. A company should practice prudent cash management policies and should only be reimbursed by ratepayers if the Company has efficiently managed its resources. Accordingly, as shown on Schedule MDC-3, page 3, I have recalculated SWG's income tax lag reflecting the 10% payment due in the following year. This adjustment increases the income lag from 37 days to 59.55 days.

Q. Please discuss your disagreement with the Company's calculation of Other O&M lag days.

A. The Company has computed lag days of 6.32 for its Other O&M expenses. This is an unusually short lag period for general O&M expenses, which typically are not due and payable except once a month.

Q. Did you examine the Company's calculation and determine why it generated such a short lag period for Other O&M expenses?

A. Yes. The Company's calculation is based on the monthly payment lags on individual vouchers that passed through its Accounts Payable account during the test year. Upon closer examination, it became apparent that the Company's calculations for the months of January, February, and April, had yielded substantial lead times for payments of expenses in those months. I then examined the vouchers that contributed to those expense leads and learned that although the Company had classified these vouchers as expenses, they were, in fact, prepayments.

Q. What is the difference between an expense and a prepayment?

A. An expense is an expenditure that provides a good or service that provides a benefit for a period of less than a year. Expenses are recorded on a company's income statement and become part of annual operating expenses. A prepayment is an expenditure that is made prior to the receipt of goods and services and provides a benefit for a period of one year or more. Prepayments are recorded on the balance sheet and amortized over the period in which they benefit.

Q. How did the Company's misclassification of these prepayments as expenses affect its calculation of cash working capital requirements?

A. This misclassification overstates the Company's cash working capital requirement by incorrectly attributing significant lead times for expenses that are, in fact, prepayments.

Q. What adjustment have you made?

A. I have removed the prepayments from the Other O&M lead/lag calculation and recomputed the lags days net of the prepayments. As shown on Schedule MDC-3, page 4, this increases the lag days for Other O&M from 6.32 days to 31.05 days. Next, as shown on Schedule MDC-3, page 5, I increased the Company's test year prepayment balance to include the prepayments that it had misclassified as expenses and then recalculated a 13-month average that included monthly amortization of the prepayment. This portion of the adjustment increased working capital by $625,957. Finally, I applied my recommended lag days to RUCO's recommended level of operating expense.

OPERATING INCOME

Operating Adjustment #8 - Compliance with Sarbanes Oxley Act

Q. What is the Sarbanes Oxley Act?

A. The Sarbanes Oxley Act (the Act) was enacted by Congress in 2000, largely in response to recent incidents that involved corporate fraudulent accounting practices. The Act, among other things, is intended to improve the accuracy and reliability of corporate disclosures made pursuant to securities laws. It imposes additional responsibilities and workload on both corporations and external auditors.

Q. Is the Company requesting any proforma adjustments related to the cost of complying with the Sarbanes Oxley Act?

A. Yes. The Company is requesting recovery of the estimated annual recurring cost of compliance with the Act, and for a deferral accounting order that would allow it to recover the initial one-time costs of Sarbanes Oxley compliance. SWG requests a three-year amortization of its estimated 2004 and 2005 one-time costs.

Q. Did you agree with the Company's estimates?

A. No. Pursuant to discovery, the Company provided documentation supporting the actual costs it had incurred in complying with the Act. Since the actual annual cost of compliance is now known and measurable, I have adjusted test year on-going O&M costs to reflect the actual cost of compliance to the Act. The initial one-time costs are also now known and I have adjusted amortization expense to reflect the actual initial one-time costs. This adjustment is shown on Schedule MDC-4, and increases test year expenses by $302,006 and decreases test year amortization expense by $12,932. I have also made an adjustment to remove the

Sarbane Oxley expenses that were recorded on the test year operating statement. Since the Company has requested deferral accounting and amortization for the test year recorded amounts, it is necessary to remove these amounts from the test year adjusted operating expense to avoid a double count. This portion of the adjustment decreases test year expenses by $61,990.

Operating Adjustment #11 - Leak Survey and Repair

Q. Please discuss the Company's proposed adjustment to test year leak survey and repair costs.

A. As discussed earlier in the rate base section of my testimony, Decision No. 58693 requires SWG to annually write off a percentage of its replacement costs for defective pipe. That decision also required the same annual percentage write off of the O&M cost of surveying and repairing leaks of the defective pipe. SWG is proposing the same modification to its required write offs of the O&M costs of defective pipe as it did the capital costs.

Q. Do you agree with the Company's proposal?

A. As discussed in Rate Base Adjustment #2, I believe on a going forward basis the Company-proposed 40 year life for purposes of writing off defective pipe is fair and reasonable and I have no objection to modifying the future write off schedule in the manner proposed by the Company.

Accordingly, no adjustment is proposed here for going forward leak survey and repair costs.

Operating Adjustment #12 -Transmission Integrity Management Program

Q. What is the Transmission Integrity Management Program?

A. The Transmission Integrity Management Program (TRIMP) is a program required under the Pipeline Safety Improvement Act of 2002 (the PSI Act). The PSI Act required the Office of Pipeline Safety and the Research and Special Programs Administration to promulgate regulations setting standards for transmission pipeline risk analysis and for the adoption and implementation of a pipeline integrity management program.

Q. Has SWG begun implementation of a TRIMP?

A. Yes. SWG began working on its baseline assessments for this program in 2004 and began repairs and replacements pursuant to this program in 2005. The Company is seeking a deferral accounting order for the estimated 2004 and 2005 initial costs of the TRIMP.

Q. What treatment is the Company requesting in the current case for TRIMP costs?

A. The Company is requesting that the estimated initial costs it will incur through the end of 2005 be deferred and amortized over three years. It is also requesting recovery of the annual on-going estimated cost of maintaining the TRIMP. The Company estimates the annual amortization of the 2004 and 2005 costs to be $1,183,333 and the on-going annual expense is estimated at $2,091,964.

Q. Do you agree with these estimates?

A. No. In RUCO data request 2-4 I asked the Company to provide all costs incurred to date for the TRIMP, to explain how it estimated the annual on-going costs of the TRIMP, and to update its on-going cost estimates, if applicable. In response, the Company provided the amounts it had actually deferred in 2004 and 2005, and provided the following information pursuant to its estimates of the on-going costs:

> The Company derived the estimates shown on Workpaper Schedule C-2 Adj., Sheets 1 of 3, based on information provided by the American Gas Association. The direct assessment costs were originally estimated to be $10,000 a mile. The Company has updated these estimates based on its experience to date.

Q. What adjustment are you proposing?

A. The costs the Company has actually experienced related to the TRIMP are significantly lower than those it estimated when putting the rate application together. Since the actual costs are now known and measurable, these amounts should be used for purposes of setting rates. On Schedule MDC-5, I have recalculated the revenue requirement associated with the TRIMP based on actual costs. In addition, I am recommending a seven-year amortization of the 2004 and 2005 costs, and believe it is more appropriate than the Company-proposed three-year amortization. The TRIMP program has a life cycle of ten years. My proposed seven-year amortization would spread the deferred costs over the remaining life cycle of the program. My adjustment for TRIMP reduces amortization expense by $1,044,968 and test year annual expenses by $1,488,287.

Operating Adjustment #17 - Amortization of Miscellaneous Intangible Plant

Q. Are you recommending an adjustment to the Company's proposed level of Amortization expense of its System Allocable Miscellaneous Intangible Plant?

A. Yes. As discussed in Rate Base Adjustment #4, the Company is requesting the removal of certain Miscellaneous Intangible Plant items because amortization of those plant items expired (i.e. was recovered) by December 31, 2004. The Company has also proposed an adjustment that would recognize new Intangible Plant items that were put in service by December 31, 2004. The Company's proposed adjustment utilized estimated in-service dates as well as estimated completed costs. The actual costs and in-service dates are now known, and accordingly I have adjusted these plant items to reflect actual costs and to remove one item that was not completed by December 31, 2004. This adjustment is shown on Schedule MDC-6 and decreases the amortization expense for Miscellaneous System Allocable Intangible Plant by $164,924.

Operating Adjustment #20 - Management Incentive Plan

Q. Are certain high-ranking employees of SWG awarded bonuses if the Company achieves specific performance objectives?

A. Yes. The Company has a bonus award system called the Management Incentive Plan (MIP). Eligibility for the MIP is limited to certain key management employees. No awards are payable under the MIP unless the Company's common stock dividend equals or exceeds the prior year's dividend and the Company's performance equals or exceeds a threshold percentage of specific performance targets.

Q. What are the performance targets?

A. The performance targets are return on equity, customers per employee, and customer satisfaction.

Q. Who benefits from the achievement of these performance targets?

A. Stockholders are the primary beneficiaries of the achievement of these performance targets. This is particularly true between rate cases.

Q. Please explain.

A. The achievement of the return on equity target clearly benefits stockholders. Any additional profits the Company is able to achieve between rate cases accrues solely to the Company's stockholders. Likewise, the achievement of the customer per employee target benefits stockholders. If the Company is successful in increasing its customer base without having to increase its number of employees, the additional profit will accrue to stockholders between rate cases. Accordingly, since stockholders stand to gain the most from achievement of the performance targets, stockholders should bear most of the cost of the MIP.

Q. Do employees who are eligible for the MIP awards also receive annual pay increases?

A. Yes. Awards made under the MIP are in addition to annual salary increases.

Q. Is the annual amount of the MIP a known and measurable expense?

A. No. Because the amount of the total MIP award is contingent on whether or not, and to the degree with, which the Company achieves its performance targets, the annual amount of the award is not known and measurable. For example, in 2002 the amount of the award was $2,813,935, in 2003 the amount was $3,619,075. Conceivably, if none of the performance targets are met the annual award could be zero. Thus, the amount awarded in the test year is not necessarily representative of the amount that will be incurred in subsequent years.

Q. Are you proposing an adjustment?

A. Yes. I recommend that the cost of the MIP be shared two-thirds by shareholders and one-third by ratepayers. Shareholders stand to enjoy the majority of the benefits realized through achievement of the MIP performance targets, particularly between rate cases. Amounts awarded under the MIP can be viewed as bonuses, since the selected individuals eligible for the award also receive wage and salary increases. Furthermore, the amount of the award is not known and measurable and conceivably could be as little as zero. Any amount collected in rates in excess of the amount actually awarded will provide the Company with additional profits not warranted under its authorized rate of return.

Q. Wasn't the MIP disallowed in a prior SWG rate case?

A. Yes. In Decision No. 57745, dated February 28, 1992, the Commission found that SWG's stockholders should bear the cost of the management bonuses. The decision allocated 100% of the cost of these bonuses to stockholders.

Q. Why then are you recommending a sharing of these costs between ratepayers and stockholders?

A. Since the issuance of Decision No. 57745, the Company has revised the criteria upon which the MIP bonuses are awarded. Previously the bonuses were based solely on the Company's achieved return on equity. As just discussed, the current MIP is based on return on equity, customers per employee ratios, and customer satisfaction. With the addition of the customer satisfaction criterion RUCO believes the bonus plan provides some benefit to customers, although the return on equity and customers per employee ratios continue to benefit primarily shareholders in the short run. Accordingly, I am recommending a sharing of the cost of the MIP.

Q. What adjustment have you made?

A. I have removed 67% of the test year cost of the MIP from test year expenses. This decreases expenses by $2,563,384.

DEMAND SIDE MANAGEMENT PROGRAMS

Q. Does SWG currently have any Demand Side Management Programs in place?

A. Yes. SWG currently has a Low Income Energy Conservation program and an Energy Advantage Pus program. Funding for these programs currently is $1,250,000, which is recovered through a $0.00486 surcharge per therm on residential customers.

Q. Is SWG proposing and changes to its DSM programs?

A. Yes. SWG is proposing to expand the scope of its current programs as well as establish some new programs. The Company's current DSM programs serve solely residential customers. The proposed DSM programs would also include programs for commercial and industrial customers. SWG proposes to increase its DSM funding to $4,385,000, and maintain the current surcharge recovery method. The surcharge would increase from the current $0.00486 per therm to $0.00724, however all customers would pay the surcharge, rather than solely residential customers which is the status quo.

Q. Does RUCO support expansion of SWG's DSM programs?

A. Yes. RUCO historically has advocated an aggressive approach to DSM. Well planned and funded DSM programs can go a long way to control load growth, forgo or at least forestall additional investment in capacity, as well as provide tools for customer bill management. DSM programs when properly designed and administered can be very cost effective. An aggressive DSM approach in a regulated monopoly model, as is the case here, can generate significant savings and benefits for ratepayers as well as stockholders.

Q. Does RUCO agree with the level of funding proposed by the Company?

A. Yes. The ratio between SWG's proposed DSM funding level and its test year revenues is nearly identical to the ratio that was approved for APS in its recent rate case. Further, the proposed increased funding level is material enough to allow a meaningful ramp up in the current level of DSM activity, and to broaden the reach of the programs to include commercial and industrial customers.

Q. Does RUCO agree with the DSM program design and approval process as proposed by the Company?

A. No. The Company has proposed a design and approval process that is the same as that utilized ten years ago. It merely provides that the funding level would be approved in this docket and then SWG would submit its proposed programs to ACC Staff for approval. Given the significant increase in funding that ratepayers will be required to pay for a more aggressive DSM approach, RUCO believes that the old procedures should be modified to insure that the DSM are dollars utilized in the most efficient and beneficial manner.

Q. How does RUCO propose that would be accomplished?

A. RUCO proposes a process similar to that which was adopted by the Commission in the recent APS rate case. The Commission in that case authorized a significant increase in DSM spending, as is requested here, and also saw fit to modify the design and approval process.

Q. Please outline RUCO's recommended process.

A. RUCO recommends the following design and approval process:

1) A collaborative DSM working group would be implemented and maintained to solicit and facilitate stakeholder input, advise SWG on program implementation, develop future DSM programs, and review DSM program performance. The DSM group would review draft DSM programs prior to submission to the Commission; however, SWG would retain responsibility for demonstrating to the Commission the appropriateness of its proposals. If SWG were to decide not to submit a DSM program, which was considered by the DSM group, any member of the group would be permitted to submit that proposal to the Commission. At minimum ACC Staff, RUCO, SWEEP, WRA, and any other party to this docket would be invited to participate in the DSM group.

2) The approval process would require that completed draft programs would be submitted Staff for review, and then docketed and submitted for Commission approval.

Q. What is SWG's position regarding net revenue that potentially could be lost as a result of an aggressive DSM approach?

A. The Company indicates that its proposed CMT mechanism would allow it to recover any net revenues lost as a result of the more aggressive DSM approach.

Q. Leaving aside RUCO's position as a whole on SWG's proposed CMT mechanism, do you believe that it is appropriate to embed in today's rates a recovery mechanism for potential future changes in consumption levels resulting from DSM programs?

A. No. Such a notion violates myriad ratemaking principles including the matching, and known and measurable principles, as well as the undesirability of piecemeal ratemaking concept. Such a mechanism would single out one element of ratemaking formula for adjustment and ignore changes in other ratemaking factors such as growth, increases or decreases in expenses, investment, and capital costs. Mismatches would result, potentially creating biased and unfair rates. Changes in consumption levels that result from DSM measures should be examined only in the context of a rate case where all other elements of the ratemaking formula can also be examined.

Q. Please summarize RUCO DSM position.

A. RUCO recommends the following:

1) Approval of the increased level of DSM funding in the amount of $4,385,00, as proposed by SWG;

2) Expansion of the current scope of the DSM programs to also include commercial and industrial customers;

3) Retention of the current surcharge recovery method modified to include commercial and industrial customers;

4) Creation of a DSM collaborative group;

5) A requirement that proposed DSM programs must be submitted and receive Commission approval prior to implementation; and

6) A requirement that potential changes in revenue levels as a result DSM efforts will be examined in SWG's next rate case and addressed in that context.

RATE DESIGN

Conservation Margin Tracker

Q. What is the Conservation Margin Tracker?

A. The Conservation Margin Tracker (CMT) is a mechanism proposed in the instant case by SWG which according to their witness would "decouple Southwest's recovery of residential authorized non-gas revenue (margin) per customer from the level of sales."

Q. What does that mean?

A. Effectively, the proposed CMT would operate as a take or pay charge. The mechanism would measure each residential customer's month-to-month consumption against the average level of residential monthly consumption embedded in the rates (average residential margin per customer) ultimately authorized in this docket. To the extent that a customer used less than the average residential margin per customer it would be billed for that shortfall. Likewise, if more than the average were used, the customer would not be billed for the margin used above average. The Company claims this mechanism is necessary to compensate for the revenue that will be lost as a result of their DSM efforts.

Q. Please discuss RUCO's view of the proposed CMT.

A. RUCO does not support the proposed mechanism, and believes it will result in biased rates. First, the mechanism would require customers to pay for a predetermined level gas service regardless of whether that level was actually used. Second, the mechanism as proposed is restricted to residential customers despite the fact that commercial and industrial customers are also targeted under SWG's proposed DSM programs. Lastly, despite the Company's argument that the mechanism is necessary because its costs are primarily fixed in nature so that decreases in consumption do not result in decreases in cost to serve, that argument does not warrant implementation of a mechanism that would have customers pay for therms they did not consume. In fact, a mechanism that sent such a price signal would be counterproductive, especially when coupled with increased DSM conservation efforts.

Q. Has SWG proposed this type of rate adjustor mechanism in any other of its rate jurisdictions?

A. Yes. SWG proposed this type of mechanism in its recent Nevada rate case. In that proceeding the Company called the mechanism the "Margin Per Customer Balancing Provision (MCB)", however, substantively it functioned in the same manner as the CMT proposed in this docket.

Q. How did the Nevada Commission rule regarding this issue?

A. The Commission denied the mechanism, stating:

> There can be no question that establishing the MCB as proposed by Southwest would be a significant change from current practices. Before a significant change is authorized, the Commission must be able to arrive at the conclusion that the proposed change is the right thing to do to address the perceived problem. The Commission cannot conclude that the evidence is compelling to establish the MCB, especially prior to using other more recognized alternatives. Consequently, the Commission is not prepared to amend Southwest's billing practice in such a drastic manner at this time. [Order of the Public Utilities Commission of Nevada in Docket No. 04-0311, Pg. 76, Southwest Gas Corporation]

Q. Do you agree with the opinions express by the Nevada Commission regarding the proposed mechanism?

A. The Nevada Commission appears to have reached some of the same conclusions as RUCO. An automatic adjustor mechanism that would bill customers for therms it did not use not only is inherently unfair, but also is conceptually unacceptable. It certainly is an extreme and unprecedented resolution to a routine rate design issue.

Q. What is the routine rate issue that needs to be resolved in this proceeding?

A. The issue is simply how should the revenue requirement established in this case be allocated among the various rate schedules, and allocated between the commodity rates and the monthly service charge. The solution to this issue should balance the following three goals:

1) Result in a fair and reasonable rates for each rate schedule;
2) Encourage energy efficient usage;
3) Give the Company a fair opportunity to realize its authorized rate of return.

RUCO believes its proposed rate design will achieve these somewhat conflicting goals without resorting to extreme measures such as the proposed CMT. Accordingly, RUCO recommends that the proposed CMT be denied and in its stead that RUCO's recommended rate design be adopted in resolution of the above-identified ratemaking goals.

Rate Structure

Q. Please discuss the salient features of your proposed rate design.

A. RUCO is proposing four fundamental changes in SWG's current rate design, which are as follows:

1) Shift a portion of the revenue requirement that is currently recovered from the commodity rates to the fixed monthly charge;
2) Flatten the current declining tier commodity rate structure to one uniform commodity rate for all usage;
3) Add a new residential rate schedule for multi-family housing; and
4) Eliminate the summer and winter rate structure differential.

Q. Please describe your first fundamental change to SWG's existing rate structure.

A. I have reallocated some of the revenue that the Company currently recovers from its commodity charges to the monthly service charge.

Q. Please explain how this reallocation was accomplished.

A. Utilizing SWG's test year revenue under the current rate structure, I calculated the percentage of total revenue that is recovered from residential and commercial customers, respectively. Current residential rates generate 67.16% of the total revenue requirement and commercial rates generate 32.84%. My recommended rate design holds this percentage constant. As a result, my recommended rate design does not shift revenue from one class to another. Next, I calculated the percentage of residential revenue at current rates that is recovered through the monthly service charge and the percentage of commercial revenue that is recovered through the monthly service charge. These percentages were 37.42% for the residential class and 24.65% for the commercial class. I then increased the percentages that will be recovered from the monthly service charge for the residential class and for the commercial class. My recommended rate structure will generate 41.16% of the residential revenue from the monthly service charge and 32.05% of the commercial revenue from the monthly service charge. This also had the effect of decreasing the amount of revenue to be recovered through the commodity charges.

Q. Why are you recommending a shift in revenue recovery from the commodity rate to the fixed monthly charge?

A. As discussed earlier, RUCO opposes SWG's proposed CMT mechanism. However, this is not to say that many of the issues and concerns the Company cites for wanting a CMT do not have some validity. These concerns include the continued decline in average customer consumption, the relative proportion between the Company fixed and variable costs to its existing fixed and variable rates, and the resultant strain that puts on the Company's opportunity to recover its authorized rate of return.

RUCO's recommended incremental shift in revenue recovery from variable rates (commodity) to fixed rates (monthly service charge) is designed to move the current rate structure to more accurately mirror the fixed vs. variable nature of the Company's cost of service. This shift will afford the Company a better opportunity to recover its costs, even if average customer consumption declines. My recommended rate structure also more fairly addresses the Company's fixed vs. variable rate concerns because it applies the remedy to both residential and commercial customers, whereas SWG's proposed CMT would hold residential customers responsible for the entire remedy.

Q. Please describe RUCO's second fundamental recommended change in the Company's rate structure.

A. I have eliminated SWG's two tiered declining rate structure for residential customers and replaced it with a single commodity rate for each rate schedule. This was not necessary for the commercial rate schedules because the existing rate structure is flat. Thus, under my recommended rate structure each customer within each rate schedule will pay the same amount per therm regardless of the volume consumed.

Q. Why are you recommending a flat or one-tiered rate structure?

A. SWG's current two-tiered declining rate structure is counterintuitive to energy efficient consumption. Under current rates the more therms a customer consumes over a certain threshold the less he/she will pay per therm. As discussed earlier, RUCO supports SWG's proposed expanded DSM efforts. It would be counterproductive on the one hand to support increased spending to promote energy efficient usage and at the same time recommend a rate structure that provides a discounted commodity rate to large users.

Q. Why then aren't you recommending an inclining two-tiered rate structure?

A. While an inclining two-tiered rate structure would send an even stronger energy efficiency price signal than a flat rate structure, the sole objective of an effective and fair rate design is not merely the promotion of energy efficiency. A rate structure that is based on the cost to serve the various rate classes is the cornerstone of a fair and effective rate design. While cost of service is the starting point of a good rate design, it is sometimes warranted and even desirable to make small departures from pure cost of service rate structures in an effort to send price signals designed to elicit certain behaviors. A total departure from cost of service, however, is contrary to fundamental fairness and accepted rate design principles. As a gas distribution company, SWG's cost of service declines as usage increases. Thus, a recommendation to use an inclining tier rate structure in a declining commodity cost business would depart too far from cost of service. At the same time, however, the current declining commodity rate structure is counterproductive to the energy efficiency goal of the proposed DSM programs. My recommended flat rate structure adheres more closely to cost of service and at the same time does not send a price signal that discourages energy efficiency, as would continuation of the declining rate structure.

Q. Please discuss your third change to the existing SWG rate structure.

A. My recommended rate design includes a new rate schedule (Rate Schedule G-6) within the residential class for residential multi-family homes. SWG's cost of service study reflects differences in the cost to serve multi-family residences vs. single-family residences. The new rate schedule G-6 reflects the lower cost of serving these customers. SWG's proposed rate design also includes the new rate schedule G-6, thus, in this respect RUCO's recommendation is the same as the Company's.

Q. Please discuss your fourth fundamental recommended change in the Company's rate structure.

A. My recommended rate structure eliminates the existing distinction in residential rates between summer and winter.

Q. What distinction do SWG's existing residential rates make for the summer and winter seasons?

A. SWG's existing residential monthly service charges and commodity rates are the same for summer and winter. The only distinction that the rates make between the two seasons is the break-over point between the first tier commodity rate and the second tier. The existing residential summer rates break-over point is 20 therms and the existing winter break-over point is 40 therms. Since my recommended rate design includes a flat residential commodity rate across all therm usage the distinction between summer and winter rates is no longer applicable.

Q. Why should your recommended rate structure be approved?

A. My recommended rate structure was designed specifically to address some of Company's cost recovery problems, to send a price signal that will not discourage energy efficient gas usage, while at the same time protect ratepayers from extreme and abrupt changes in their monthly bill. I believe my recommended rate design addresses those objectives through adherence to basic rate design principles of cost of service, gradualism, and the appropriate price signals.

Q. Will your recommended rate design accomplish the three goals you identified earlier?

A. Yes, I believe it will. RUCO's recommended rates are fair and reasonable, are designed to encourage energy efficient usage, and afford the Company an opportunity to recover its authorized rate of return.

Q. Does that conclude your direct testimony?

A. Yes.

APPENDIX I

Qualifications of Marylee Diaz Cortez

EDUCATION: University of Michigan, Dearborn
B.S.A., Accounting 1989

CERTIFICATION: Certified Public Accountant - Michigan
Certified Public Accountant - Arizona

EXPERIENCE: Audit Manager
Residential Utility Consumer Office
Phoenix, Arizona 85007
July 1994 - Present

Responsibilities include the audit, review and analysis of public utility companies. Prepare written testimony, schedules, financial statements and spreadsheet models and analyses. Testify and stand cross-examination before Arizona Corporation Commission. Advise and work with outside consultants. Work with attorneys to achieve a coordination between technical issues and policy and legal concerns. Supervise, teach, provide guidance and review the work of subordinate accounting staff.

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona 85004
October 1992 - June 1994

Responsibilities included the audit, review and analysis of public utility companies. Prepare written testimony and exhibits. Testify and stand cross-examination before Arizona Corporation Commission. Extensive use of Lotus 123, spreadsheet modeling and financial statement analysis.

Auditor/Regulatory Analyst
Larkin & Associates - Certified Public Accountants
Livonia, Michigan
August 1989 - October 1992

Performed on-site audits and regulatory reviews of public utility companies including gas, electric, telephone, water and sewer throughout the continental United States. Prepared integrated proforma financial statements and rate models for some of the largest public utilities in the United States. Rate models consisted of anywhere from twenty to one hundred fully integrated schedules. Analyzed financial statements, accounting detail, and identified and developed rate case issues based on this analysis. Prepared written testimony, reports, and briefs. Worked closely with outside legal counsel to achieve coordination of technical accounting issues with policy, procedural and legal concerns. Provided technical assistance to legal counsel at hearings and depositions. Served in a teaching and supervisory capacity to junior members of the firm.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Client
Potomac Electric Power Co.	Formal Case No. 889	Peoples Counsel of District of Columbia
Puget Sound Power & Light Co.	Cause No. U-89-2688-T	U.S. Department of Defense - Navy
Northwestern Bell-Minnesota	P-421/EI-89-860	Minnesota Department of Public Service
Florida Power & Light Co.	890319-EI	Florida Office of Public Counsel
Gulf Power Company	890324-EI	Florida Office of Public Counsel
Consumers Power Company	Case No. U-9372	Michigan Coalition Against Unfair Utility Practices
Equitable Gas Company	R-911966	Pennsylvania Public Utilities Commission
Gulf Power Company	891345-EI	Florida Office of Public Counsel

Jersey Central Power & Light	ER881109RJ	New Jersey Department of Public Advocate Division of Rate Counsel
Green Mountain Power Corp.	5428	Vermont Department of Public Service
Systems Energy Resources	ER89-678-000 & EL90-16-000	Mississippi Public Service Commission
El Paso Electric Company	9165	City of El Paso
Long Island Lighting Co.	90-E-1185	New York Consumer Protection Board
Pennsylvania Gas & Water Co.	R-911966	Pennsylvania Office of Consumer Advocate
Southern States Utilities	900329-WS	Florida Office of Public Counsel
Central Vermont Public Service Co.	5491	Vermont Department of Public Service
Detroit Edison Company	Case No. U-9499	City of Novi
Systems Energy Resources	FA-89-28-000	Mississippi Public Service Commission
Green Mountain Power Corp.	5532	Vermont Department of Public Service
United Cities Gas Company	176-717-U	Kansas Corporation Commission

General Development Utilities	911030-WS & 911067-WS	Florida Office of Public Counsel
Hawaiian Electric Company	6998	U.S. Department of Defense - Navy
Indiana Gas Company	Cause No. 39353	Indiana Office of Consumer Counselor
Pennsylvania American Water Co.	R-00922428	Pennsylvania Office of Consumer Advocate
Wheeling Power Co.	Case No. 90-243-E-42T	West Virginia Public Service Commission Consumer Advocate Division
Jersey Central Power & Light Co.	EM89110888	New Jersey Department of Public Advocate Division of Rate Counsel
Golden Shores Water Co.	U-1815-92-200	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-92-135	Residential Utility Consumer Office
Sulphur Springs Valley Electric Cooperative	U-1575-92-220	Residential Utility Consumer Office
North Mohave Valley Corporation	U-2259-92-318	Residential Utility Consumer Office
Graham County Electric Cooperative	U-1749-92-298	Residential Utility Consumer Office

Graham County Utilities	U-2527-92-303	Residential Utility Consumer Office
Consolidated Water Utilities	E-1009-93-110	Residential Utility Consumer Office
Litchfield Park Service Co.	U-1427-93-156 & U-1428-93-156	Residential Utility Consumer Office
Pima Utility Company	U-2199-93-221 & U-2199-93-222	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-94-306	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-182	Residential Utility Consumer Office
Paradise Valley Water	U-1303-94-310 & U-1303-94-401	Residential Utility Consumer Office
Pima Utility Company	U-2199-94-439	Residential Utility Consumer Office
SaddleBrooke Development Co.	U-2492-94-448	Residential Utility Consumer Office
Boulders Carefree Sewer Corp.	U-2361-95-007	Residential Utility Consumer Office
Rio Rico Utilities	U-2676-95-262	Residential Utility Consumer Office
Rancho Vistoso Water	U-2342-95-334	Residential Utility Consumer Office
Arizona Public Service Co.	U-1345-95-491	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-473	Residential Utility Consumer Office
Citizens Utilities Co.	E-1032-95-417 et al.	Residential Utility Consumer Office

Paradise Valley Water	U-1303-96-283 & U-1303-95-493	Residential Utility Consumer Office
Far West Water	U-2073-96-531	Residential Utility Consumer Office
Southwest Gas Corporation	U-1551-96-596	Residential Utility Consumer Office
Arizona Telephone Company	T-2063A-97-329	Residential Utility Consumer Office
Far West Water Rehearing	W-0273A-96-0531	Residential Utility Consumer Office
SaddleBrooke Utility Company	W-02849A-97-0383	Residential Utility Consumer Office
Vail Water Company	W-01651A-97-0539 & W-01651B-97-0676	Residential Utility Consumer Office
Black Mountain Gas Company Northern States Power Company	G-01970A-98-0017 G-03493A-98-0017	Residential Utility Consumer Office
Paradise Valley Water Company Mummy Mountain Water Company	W-01303A-98-0678 W-01342A-98-0678	Residential Utility Consumer Office
Bermuda Water Company	W-01812A-98-0390	Residential Utility Consumer Office
Bella Vista Water Company Nicksville Water Company	W-02465A-98-0458 W-01602A-98-0458	Residential Utility Consumer Office
Paradise Valley Water Company	W-01303A-98-0507	Residential Utility Consumer Office
Pima Utility Company	SW-02199A-98-0578	Residential Utility Consumer Office
Far West Water & Sewer Company	WS-03478A-99-0144 Interim Rates	Residential Utility Consumer Office
Vail Water Company	W-01651B-99-0355 Interim Rates	Residential Utility Consumer Office

Far West Water & Sewer Company	WS-03478A-99-0144	Residential Utility Consumer Office
Sun City Water and Sun City West	W-01656A-98-0577 & SW-02334A-98-0577	Residential Utility Consumer Office
Southwest Gas Corporation ONEOK, Inc.	G-01551A-99-0112 G-03713A-99-0112	Residential Utility Consumer Office
Table Top Telephone	T-02724A-99-0595	Residential Utility Consumer Office
U S West Communications Citizens Utilities Company	T-01051B-99-0737 T-01954B-99-0737	Residential Utility Consumer Office
Citizens Utilities Company	E-01032C-98-0474	Residential Utility Consumer Office
Southwest Gas Corporation	G-01551A-00-0309 & G-01551A-00-0127	Residential Utility Consumer Office
Southwestern Telephone Company	T-01072B-00-0379	Residential Utility Consumer Office
Arizona Water Company	W-01445A-00-0962	Residential Utility Consumer Office
Litchfield Park Service Company	W-01427A-01-0487 & SW-01428A-01-0487	Residential Utility Consumer Office
Bella Vista Water Co., Inc.	W-02465A-01-0776	Residential Utility Consumer Office
Generic Proceedings Concerning Electric Restructuring Issues	E-00000A-02-0051	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-02-0707	Residential Utility Consumer Office
Qwest Corporation	RT-00000F-02-0271	Residential Utility Consumer Office

Arizona Public Service Company	E-01345A-02-0403	Residential Utility Consumer Office
Citizens/UniSource	G-01032A-02-0598 E-01032C-00-0751 E-01933A-02-0914 E-01302C-02-0914 G-01302C-02-0914	Residential Utility Consumer Office
Arizona-American Water Company	WS-01303A-02-0867	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-03-0437	Residential Utility Consumer Office
UniSource	E-04230A-03-0933	Residential Utility Consumer Office
Arizona Public Service Company	E-01345A-04-0407	Residential Utility Consumer Office
Qwest Communications, Inc.	T-01051B-03-0454 et al.	Residential Utility Consumer Office

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJ #2 - PIPE REPLACEMENT

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-1

LINE NO.	DESCRIPTION	2000	2001	2002	2003	2004	PLANT ADJUSTMENT	ACCUMULATED DEPRECIATION	DEFERRED TAXES
	ALDYL HD MAINS								
1	REPLACEMENT COST	$15,796	150,399	91,463	82,185	39,107			
2	DISALLOWANCE %	69%	68%	67%	66%	65%			
3	DISALLOWANCE	10,899	102,271	61,280	54,242	25,420	254,112	(32,436)	(18,044)
	ALDYL HD SERVICES								
4	REPLACEMENT COST	203,854	564,117	580,723	728,319	650,523			
5	DISALLOWANCE %	69%	68%	67%	66%	65%			
6	DISALLOWANCE	140,659	383,600	389,084	480,691	422,840	1,816,874	(262,907)	(147,597)
	ALDYL A MAINS								
7	REPLACEMENT COST	149,649	353,479	221,454	938,175	505,054		(133,150)	(312,132)
8	DISALLOWANCE %	29.5%	28.5%	27.5%	26.5%	25.5%		27.5%	27.5%
9	DISALLOWANCE	44,146	100,742	60,900	248,616	128,789	583,193	(36,616)	(85,836)
	ALDYL A SERVICES								
10	REPLACEMENT COST	281,898	188,129	462,608	239,342	138,873		(164,202)	(131,110)
11	DISALLOWANCE %	29.5%	28.5%	27.5%	26.5%	25.5%		27.5%	27.5%
12	DISALLOWANCE	83,160	53,617	127,217	63,426	35,413	362,832	(45,156)	(36,055)
	1960s STEEL MAINS								
13	REPLACEMENT COST	502,862	412,904	1,030,498	1,982,344	1,122,435		(317,916)	(733,426)
14	DISALLOWANCE %	12.5%	11.5%	10.5%	9.5%	8.5%		10.5%	10.5%
15	DISALLOWANCE	62,858	47,484	108,202	188,323	95,407	502,274	(33,381)	(77,010)
	1960s STEEL SERVICES								
16	REPLACEMENT COST	213,653	289,859	360,912	222,417	206,039		(154,667)	(129,542)
17	DISALLOWANCE %	12.5%	11.5%	10.5%	9.5%	8.5%		10.5%	10.5%
18	DISALLOWANCE	26,707	33,334	37,896	21,130	17,513	136,579	(16,240)	(13,602)
	ALDYL ABS MAINS								
19	REPLACEMENT COST	459	4,643	0	301,527	67,905		(14,937)	(67,084)
20	DISALLOWANCE %	18.0%	17.0%	16.0%	15.0%	14.0%		16%	16%
21	DISALLOWANCE	83	789	0	45,229	9,507	55,608	(2,390)	(10,733)
	ALDYL ABS SERVICES								
22	REPLACEMENT COST	1,572	0	0	297	0		(366)	(98)
23	DISALLOWANCE %	18.0%	17.0%	16.0%	15.0%	14.0%		0	0
24	DISALLOWANCE	283	0	0	45	0	328	(59)	(16)
25	TOTAL	368,795	721,836	784,580	1,101,701	734,888	3,711,799	(429,184)	(388,893)
26	TOTAL PER COMPANY						1,372,020	(295,343)	(165,641)
27	ADJUSTMENT						($2,339,779)	$133,841	$223,252

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJ #4 - MISC INTANGIBLE PLANT
SYSTEM ALLOCABLE

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-2

LINE NO.	DESCRIPTION	(A) COMPANY REQUESTED	(B) RUCO RECOMMENDED	(C) ADJUSTMENT
	ACCT 303 PLANT			
1	EMRS SOFTWARE	$212,459	212,459	0
2	RISER VERIFICATION	500,000	0	(500,000)
3	DB MICROWAVE SOFTWARE	277,000	267,153	(9,847)
4	SOFTWARE LICENSES - MOBILE	434,000	454,500	20,500
5	MICROFICHE SOFTWARE	50,000	44,579	(5,421)
6	165 PERPETUAL PGP	44,418	0	(44,418)
7	UTILITY PARTNERS	820,000	0	(820,000)
8	TELLER TERMINAL	405,000	0	(405,000)
9	MICROSOFT SOFTWARE	618,633	0	(618,633)
10	PLANT TOTAL	3,361,510	978,691	($2,382,819)
	ACCUM. DEPRECIATION			
11	EMRS SOFTWARE	0	0	0
12	RISER VERIFICATION	0	0	0
13	DB MICROWAVE SOFTWARE	0	0	0
14	SOFTWARE LICENSES - MOBILE	0	0	0
15	MICROFICHE SOFTWARE	0	0	0
16	165 PERPETUAL PGP	(44,418)	0	44,418
17	UTILITY PARTNERS	(797,236)	0	797,236
18	TELLER TERMINAL	(393,750)	0	393,750
19	MICROSOFT SOFTWARE	(301,440)	0	301,440
20	ACCUM. DEPRECIATION TOTAL	(1,536,844)	0	$1,536,844

REFERENCES
COLUMN (A): SCH. C-2 W/P, ADJ 17, SHEET 8 & 9
COLUMN (B): TESTIMONY MDC, RUCO DR# 2-16
COLUMN (C): COLUMN (B) - COLUMN (A)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	MATERIALS & SUPPLIES PER SWG	$9,222,489	SCH. B-5, PG. 3
2	MATERIALS & SUPPLIES PER RUCO	9,222,489	SCH. B-5, PG. 3
3	ADJUSTMENT	0	LINE 2 - LINE 1
4	PREPAYMENTS PER SWG	2,740,815	SCH. B-5, PG. 4
5	PREPAYMENTS PER RUCO	3,366,772	SCH. MDC-3, Pg 5
6	ADJUSTMENT	625,957	LINE 5 - LINE 4
7	CASH WORKING CAPITAL PER SWG	(11,082,156)	SCH. B-5, PG. 2
8	CASH WORKING CAPITAL PER RUCO	(15,357,713)	SCHEDULE MDC-3, Pg 2
9	ADJUSTMENT	(4,275,557)	LINE 8 - LINE 7
10	TOTAL ADJUSTMENT	($3,649,600)	SUM OF LINES 3, 6 & 9

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
LEAD/LAG DAY SUMMARY

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3
PAGE 2 OF 5

LINE NO.	DESCRIPTION	(A) EXPENSE PER COMPANY	(B) RUCO ADJUSTMENTS	(C) RUCO ADJUSTED	(D) (LEAD)/LAG DAYS	(E) DOLLAR DAYS
1	COST OF GAS	$298,559,015		298,559,015	43.78	13,070,913,677
2	LABOR COST	107,117,974	(4,235,547)	102,882,427	14.01	1,441,382,804
3	UNCOLLECTIBLE	1,498,151		1,498,151	120.00	179,778,120
4	OTHER O&M	45,068,143	(7,203,716)	37,864,427	31.05	1,175,546,908
5	INTEREST	40,521,530	(4,061,931)	36,459,599	87.34	3,184,381,359
6	TAXES OTHER THAN INCOME	33,455,124	(1,267,863)	32,187,261	206.50	6,646,669,500
7	INCOME TAXES	18,192,843	9,698,766	27,891,609	59.55	1,660,945,319
8	TOTAL OPERATING EXPENSES	544,412,780		537,342,489		27,359,617,686
9	EXPENSE LAG				50.92	
10	REVENUE LAG				40.62	
11	NET LAG				(10.30)	
12	CASH WORKING CAPITAL	($15,357,713)				

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF INCOME TAX LAG

LINE NO.	MID-POINT OF SERVICE PERIOD	PAYMENT DATE	PERCENT PAYMENT	(LEAD)/LAG DAYS	DOLLAR DAYS
1	7/1/2003	4/15/2003	22.50%	(77)	(17.33)
2	7/1/2003	6/15/2003	22.50%	(16)	(3.60)
3	7/1/2003	9/15/2003	22.50%	76	17.10
4	7/1/2003	12/15/2003	22.50%	167	37.58
5	7/1/2003	3/15/2004	10.00%	258	25.80
6	TOTALS		100.00%		59.55
7	INCOME TAX LAG			59.55	

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF OTHER O&M LAG

DOCKET NO. G-0155A-04-0876
SCHEDULE MDC-3

Line No.	Month	Cost	Lag Days	Dollar Days
	(a)	(b)	(c)	(d)
1	September 2003	$2,065,502	27.14	56,065,384
2	October 2003	2,281,209	24.19	55,183,873
3	November 2003	2,122,438	14.51	30,806,560
4	December 2003	2,799,950	19.45	54,459,832
5	January 2004	1,619,271	76.74	124,263,026
6	February 2004	1,310,710	46.31	60,700,671
7	March 2004	2,873,308	32.15	92,368,700
8	April 2004	1,937,390	17.71	34,308,766
9	May 2004	1,865,981	24.72	46,127,781
10	June 2004	2,515,719	48.84	122,871,846
11	July 2004	3,728,708	22.06	82,248,601
12	August 2004	2,172,721	40.47	87,936,239
13	Total	$27,292,907	31.05	847,341,280

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
RATE BASE ADJUSTMENT #5 - WORKING CAPITAL
CALCULATION OF ADJUSTED PREPAYMENTS

LINE NO.	MONTH	(A) BALANCE	(B) DEBITS	(C) CREDITS	(D) ADJUSTED BALANCE
1	AUGUST	$5,130,082			5,130,082
2	SEPTEMBER	4,798,680			4,798,680
3	OCTOBER	3,784,576	66,608	0	3,851,184
4	NOVEMBER	3,956,561	12,000	5,551	4,029,618
5	DECEMBER	5,938,689	119,223	6,551	6,124,419
6	JANUARY	5,258,062	697,011	16,486	6,124,317
7	FEBRUARY	4,984,761	958,218	74,570	6,734,664
8	MARCH	4,810,591	295,000	154,422	6,701,072
9	APRIL	4,204,986	408,228	179,005	6,324,690
10	MAY	4,296,987	153,500	213,024	6,357,167
11	JUNE	3,639,813	27,754	225,816	5,501,931
12	JULY	3,377,801	105,000	228,129	5,116,791
13	AUGUST	7,698,845	17,007	236,879	9,217,963
14	TOTAL	61,880,434			76,012,577
15	13 MONTH AVERAGE	$4,760,033		57.58%	$3,366,772

REFERENCES
COLUMN (A): SCH. B-5, PG. 4
COLUMN (B): SCH. B-5 W/P SHEET 30-59
COLUMN (C): COLUMN (B) PRIOR MOS. ACCRUALS / 12 MONTHS
COLUMN (D): PRIOR MONTH COLUMN (D) + CURRENT MONTH COLUMN (B) - CURRENT MONTH COLUMN (C) + CURRENT MONTH COLUMN (A) - PRIOR MONTH COLUMN (A)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ # 8 - SARBANES OXLEY

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-4

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
	ANNUAL EXPENSE		
1	ANNUAL SOX AUDIT FEES	$915,000	STAFF DR JJD 8-2
2	PAIUTE & SGTC ALLOCATION	(39,229)	STAFF DR JJD 8-2
3	SUBTOTAL	875,771	LINE 1 + LINE 2
4	ARIZONA 4-FACTOR	57.58%	SCH. C-2, ADJ. 8
5	AMT ALLOCATED TO ARIZONA	504,269	LINE 3 x LINE 4
6	AMT. AS FILED	202,263	SCH. C-2, ADJ. 8
7	ADJUSTMENT	$302,006	LINE 5 - LINE 6
	AMORT. OF DEFERRALS		
8	AMORT. OF DEFERRED SABANNES OXLEY	$14,414	STAFF JJD 8-2
9	AMOUNT PER COMPANY	27,346	SCH. C-2, ADJ. 8
10	ADJUSTMENT	($12,932)	LINE 1- LINE 2
	REMOVE DOUBLE COUNT OF T/Y SOX COSTS		
11	SOX T/Y EXPENSES - ACCTS. 921 & 923	($61,990)	STAFF DR JJD 8-2

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ #12 - TRIMP COSTS

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-5

LINE NO.	DESCRIPTION	(A) 2004	(B) 2005	(C) TOTAL	(D) AS FILED	(E) ADJUSTMENT
	DEFERRED COSTS					
1	DIRECT ASSESSMENT	414,227	254,405	668,632	887,500	
2	DIRECT EXAMINATION	0	299,925	299,925	2,662,500	
3	TOTAL DEFERRED	414,227	554,330	968,557	3,550,000	
4	7 YEAR AMORTIZATION			138,365	1,183,333 (A)	$\boxed{(1,044,968)}$
	ANNUAL EXPENSES					
5	DIRECT ASSESSMENT			218,060	380,357	(162,297)
6	DIRECT EXAMINATION			257,078	1,141,071	(883,993)
7	REPAIR AND MAINTENANCE			128,539	570,536	(441,997)
8	TOTAL O&M			603,677	2,091,964	$\boxed{(1,488,287)}$

REFERENCES
ALL REVISED ESTIMATES IN COLUMNS (A) AND (B) ARE PER RUCO DR #2-04

(A) AS FILED REFLECTS A 3 YEAR AMORTIZATION

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
OPERATING ADJ #17 - AMORTIZATION OF
SYSTEM ALLOCABLE INTANGIBLE PLANT

DOCKET NO. G-01551A-04-0876
SCHEDULE MDC-6

LINE NO.	DESCRIPTION	(A) COMPANY REQUESTED AMORT.	(B) RUCO ADJUSTED	(C) ADJUSTMENT
1	EMRS SOFTWARE	$70,820	70,820	(0)
2	RISER VERIFICATION	166,667	0	(166,667)
3	DB MICROWAVE SOFTWARE	92,333	89,051	(3,282)
4	SOFTWARE LICENSES - MOBILE	144,667	151,500	6,833
5	MICROFICHE SOFTWARE	16,667	14,860	(1,807)
6	TOTALS	$491,154	$326,230	($164,924)

REFERENCES
COLUMN (A): W/P SCH. C-2, ADJ. 17, SHEET 9
COLUMN (B): SCH. MDC- , LINES 1 THROUGH 5/3 YEARS
COLUMN (C): COLUMN B) - COLUMN (A)

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

TABLE OF CONTENTS

INTRODUCTION

Q. Please state your name, position, employer and address.

A. Rodney L. Moore, Public Utilities Analyst V
Residential Utility Consumer Office ("RUCO")
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007.

Q. Please state your educational background and work experience.

A. I obtained a Bachelor's Degree in Business Administration in 1993 from Athabasca University. I have attended several training classes and courses regarding auditing, rate design, income taxes, and other utility related matters. From 1966 to 1993, I was employed by Telus Corporation, Inc., a large telecommunication company, where I assumed various positions from lineman to office administrator. In 1995, I began my employment with the Arizona Corporation Commission ("ACC" or "Commission"). I worked in the Consumer Service Section until accepting a position as an Auditor in October 1999 with the Accounting and Rates Section. In May of 2001, I succeeded to my current position at RUCO. My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Southwest Gas Corporation's ("Company" or "SWG") application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for gas service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended August 31, 2004.

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, the Company's overall revenue requirement and rate design. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of fifteen sets of data requests, the review and analysis of Company responses to Commission Staff data requests, conversations with Company personnel and the review of prior ACC dockets related to SWG.

The Commission in Decision No. 64172, dated October 30, 2001, approved the Company's present rates and charges for utility service. The test year used in that proceeding was the 12-month period ending December 31, 1999.

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Q. What areas will you address in your testimony?

A. I will address issues related to rate base, operating income, revenue requirements and rate design. RUCO's witness William A. Rigsby will provide an analysis of the cost of capital as presented on Schedule RLM-18. RUCO's witness Marylee Diaz Cortez will also address additional issues related to rate base, operating income, rate design and revenue requirements.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring Schedules numbered RLM-1 through RLM-18.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and rate design issues addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

<u>Fair Value Rate Base</u> – This adjustment states the fair value rate base by giving equal weighting (50/50 split) to RUCO's adjusted original cost rate base and RUCO's calculation of the reconstruction cost new depreciated rate base.

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Test-Year In Service Plant and Accumulated Depreciation – This adjustment restates gross test-year gas plant in service and the accumulated depreciation value to reflect RUCO's adjustments.

Operating Income

Labor Annualization Expense – This adjustment reduces test-year operating expenses to reflect RUCO's recommended level of annualized payroll and payroll taxes.

Uncollectibles Annualization Expense – No adjustment.

Promotional Expense – No adjustment.

American Gas Association Dues – This adjustment removes the portion of the dues dedicated to advertising and lobbying.

Paiute Allocation Annualization Expense – No adjustment.

Injuries and Damages Expense – This adjustment reflects RUCO's determination of an average annual level of expense.

Rate Case Expense – RUCO is proposing no adjustment at this time, but reserves the right to make an adjustment to the rate case expenses after an assessment of actual costs is made.

Miscellaneous Expense – RUCO expanded the scope of the Company's proposed adjustment to miscellaneous expense adjustments and removed inappropriate expenditures not necessary in the provisioning of gas service.

Vehicle Compensation Expense – No adjustment.

Out of Period Expense – No adjustment.

Property Taxes Expense - This adjustment reflects the appropriate level of property tax expense given RUCO's recommended level of net plant in service.

Interest on Customer Deposits expense – No adjustment.

RUCO Adjustments To Test-Year Operating Expenses – This adjustment reflects RUCO's determination to remove the supplemental executive retirement plan.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

Rate Design

In the instant case, I was responsible to produce an accurate set of bill determinants. Therefore, I revised the bill determinants to reflect updated bill frequency analyses provided by the Company and RUCO's adjustment to correctly produce test-year revenues. I then imputed revised bill determinants into the Company's proposed rate design; and finally annualized the imputed bill determinants utilizing the Company's pro forma adjustments. Ms. Marylee Diaz Cortez will discuss RUCO's proposed rate design in her testimony.

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REVENUE REQUIREMENTS

Q. Please summarize the results of your analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, I am recommending that the Company's revenue requirement not exceed:

SWG	RUCO	DIFFERENCE
$393,675,106	$370,818,589	($22,856,517)

My recommended decrease in Fair Value Rate Base ("FVRB") based on the equal weighting of a 50/50 split between Original Cost Rate Base ("OCRB") and Reconstruction Cost New Depreciated Rate Base ("RCND") is summarized on Schedule RLM-1:

SWG	RUCO	DIFFERENCE
$1,171,427,301	$1,163,910,949	($7,516,352)

The detail supporting my recommended rate base is presented on Schedules RLM-2, RLM-3, RLM-4, and RLM-5.

My recommended increase in required operating income is shown on Schedule RLM-1 as:

SWG	RUCO	DIFFERENCE
$86,957,942	$79,378,637	($7,579,305)

My recommended revenue requirement percentage increase versus the Company's proposal is as follows:

SWG	RUCO	DIFFERENCE
21.93 %	14.85 %	-7.08 %

Schedule RLM-1 presents the calculation of my recommended revenue requirement.

RATE BASE

Rate Base Adjustment No. 1 – Fair Value Rate Base

Q. Please explain the basis for your determination of the fair value rate base ("FVRB").

A. RUCO's determination of the FVRB consists of three elements. First, as shown on RLM-2, the value of the OCRB was restated to reflect RUCO's adjustment to the various rate base determinants. Second, as shown on RLM-4, the value of the RCND was computed. Third, as shown of RLM-1, the FVRB was computed on an equally weighted basis (50/50 split) between RUCO's OCRB and RCND.

Q. Please elaborate on the first element of RUCO's FVRB determination.

A. The first element consists of several adjustments to the OCRB. The aggregate adjustment was corroborated between myself and RUCO witness Marylee Diaz Cortez. As shown on RLM-3, I was responsible for analyzing the Construction Completed Not Classified ("CCNC"), while Ms. Cortez calculated the remaining adjustments.

The CCNC was adjusted to reflect information received from the Company in its response to RUCO data request number 13. I only considered CCNC projects that were placed in service within the test year. Moreover, I also reduced the test year gross plant in service by removing the retired plant associated with the appropriate CCNC projects.

My adjustment to CCNC is shown on supporting Schedule RLM-4. Please see Ms. Diaz Cortez testimony for explanation of the other rate base adjustments on Schedule RLM-3.

Q. Please elaborate on the second element of RUCO's FVRB determination.

A. The second element is the computation of the RCND. RUCO's RCND was computed by multiplying RUCO's OCRB by the percentage difference between the Company's OCRB and its RCND as filed.

Q. Please elaborate on the third element of RUCO's FVRB determination.

A. The third element is the computation of the FVRB. RUCO computed the FVRB by calculating a 50/50 split between RUCO's OCRB and its RCND.

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This adjustment to fair value rate base decreased the test-year rate base by:

$6,765,240.

OPERATING INCOME

Operating Income Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. As shown on Schedule RLM-7, pages 1 through 2, columns (B) through (Q), RUCO analyzed the Company's nineteen adjustments to its historical test-year operating income and made several adjustments to the operating income as filed by the Company. RUCO witness Ms. Cortez testimony discusses seven of the adjustments, while I was responsible for reviewing twelve of the adjustments the Company proposes to its test-year operating income, and finally, through discovery, RUCO recommends other adjustments. My review, analysis and adjustments are explained below.

SWG Operating Income Adjustment No. 3 – Labor Annualization

Q. Please discuss the Company's proposed labor expense adjustment.

A. The Company has proposed an adjustment that increases historical test - year labor and labor loading expense by $1,638,419.

. . .

Q. What elements did the Company include in this labor annualization adjustment number 3?

A. In the aggregate amount of adjustment number 3, the Company considered all the determinants of labor and labor loading expenses, which impact the total labor costs of SWG's.

Q. What elements did you include in your adjustment to the Company's adjustment number 3?

A. My adjustments to the Company adjustment number 3 only reflect labor costs and the payroll taxes. For clarification purposes, other adjustments to SWG's annualized labor expenses are discussed later in RUCO testimony and separately supported under Schedule RLM-14.

Q. What are the elements of the Company's proposed labor expense adjustment?

A. The Company's proposed adjustment is comprised of the following elements:

1. Annualization of employees' salaries and wages as of the August 31, 2004 test-year-end;
2. Increase in the test-year-end annualized salaries to reflect a projected 2005 wage and salary increase of 2.00%;
3. Increase in the test-year-end annualized wages and salaries to reflect a projected 1.35% "within grade" salary and wage increase;

4. Use of the test-year overtime percentage to reflect the estimated proforma overtime expense; and

5. Use of the historical test-year O&M ratio to estimate the level of proforma O&M labor expense.

Q. Please discuss the first of these elements.

A. On June 28, of the 2004 test year, SWG's employees received a 2.00% wage increase. In its proforma labor adjustment the Company has annualized the August 2004 labor (which includes the 2.00% increase) to reflect the level of wages that would be incurred had the wage increase been in effect during the entire test year.

Q. Do you agree with this portion of the Company's proposed labor expense adjustment?

A. Yes. Since an end-of-test-year rate base is used in Arizona, the Commission has typically allowed adjustments that annualize revenues and expenses to year-end levels. Such annualizations serve to create a matching between rate base, revenues and expenses, and in the absence of extenuating circumstances, are generally appropriate. The end result of the Company's annualization adjustment is to reflect the level of wages that was in effect at August 31, 2004.

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Q. Please discuss the next element of the Company's proposed labor adjustment.

A. The Company has further increased the already annualized level of labor by an additional 2.00% to reflect a projected increase slated for June 2005.

Q. Do you agree with this portion of the Company's proposed adjustment?

A. No. The Company has already made an adjustment that annualizes the test-year-end level of salaries and wages. That annualization already serves to match rate base, revenues, and expenses. The inclusion of an additional 2.00% wage increase for 2005 would result in the use of selective projected expenses. Biased rates will result if the Company is allowed to pick and chose which rate base, expense, and revenue items it will reflect on an actual, projected or annualized basis.

Q. Are there any other reasons why the additional 2.00% wage increase proposed by the Company is inappropriate?

A. Yes. If the additional 2005 projected 2.00% wage increase were allowed, it would result in a doubling up of expenses during the test year. SWG historically has granted one wage increase per year. If the Company's proposed year-end annualization *and* the Company's proposed 2005 wage increase are both allowed the test year will contain two labor increases.

Since the Company only awards one wage increase per year this would result in a double count.

Q. Please discuss the third element of the Company's proposed labor adjustment.

A. The Company has increased the test-year-end annualized level of labor to reflect an additional 1.35% increase related to "within grade" increases.

Q. What is a "within grade" increase?

A. Each non-exempt employee position is graded. Within each grade are a number of levels through which employees pass as they meet certain performance and time criteria within the grade. Each level carries a fixed wage increase.

Q. Do you agree with this portion of the Company's proposed adjustment?

A. No. As just discussed, the Company has already annualized its test year labor to reflect the year-end level of labor. Thus, any "within grade" wage increases granted through the end of the test year are already included in the Company's proposed labor by virtue of the Company's annualization adjustment. Inclusion of an additional 1.35% increase would have the effect of double counting the test year "within grade" increases.

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Q. Please discuss the fourth element of the Company's proposed labor adjustment.

A. The Company has increased its annualized level of labor expense by 8.53% (Arizona), 2.77% (Corporate Direct), and 0.43% (System Allocable), which represent the test-year overtime percentage.

Q. Do you agree with this portion of the Company's adjustment?

A. I agree that it is appropriate to include the historical level of overtime in the annualized level of labor. However, the manner in which the Company has calculated the annualized level of overtime results in an overstatement of overtime labor expense.

Q. Please explain.

A. The Company calculated its test year annualized labor by taking each employee position's salary and wages as of August 31, 2004 and annualizing that amount to reflect 12 months of that level of earnings. In response to RUCO data request 2.08 the Company provided the underlying data that supports that calculation. Pursuant to my review of that information I became aware that the annualized salaries calculated by the Company included both base wages *and* incentive compensation that was paid to certain sales and marketing personal. Thus, when the Company applies the historical overtime percentage to the total annualized labor it has the effect of attributing additional overtime dollars to the salaries of the sales and marketing personal. Payroll dollars related to SWG's marketing and sales employee should be disallowed as a rate case expense.

Q. Does SWG incur any payroll expense related to sales, marketing, and promotional activities?

A. Yes. Specifically, SWG has 37 employees who fill positions whose primary responsibilities include the marketing of gas and gas products.

Q. Please explain the Company's adjustment to the Sales and Marketing Payroll expense.

A. The Company has made adjustment number 6 that decreases test-year expenses by $552,091 to remove certain marketing, selling, and promotional expenses that have been disallowed in prior SWG rate cases. The costs removed relate only to third party vendors and do not include any payroll dollars related to SWG employees' marketing, sales and promotional efforts.

Q. Are the duties and responsibilities of these positions the type of activities the Commission has excluded from rates in the past?

A. Yes. The Commission has previously disallowed the cost of sales, marketing and promotional activities. As previously mentioned, the Company has removed over a half million dollars in marketing and promotional costs in this rate application. In its testimony and in response to data requests SWG acknowledges that marketing and promotional activities traditionally have not been included as a component of rates. However, despite this acknowledgement the Company has failed to remove its in-house payroll associated with these activities.

Q. Who realizes the initial benefit from any increases in load resulting from these sales and marketing activities?

A. Any additional margin realized through these sales and marketing efforts accrues to shareholders between rate cases. Until such additional load is recognized in rates the only beneficiary is the stockholder.

Q. Should ratepayers be required the bear the cost of these sales, marketing, and promotional activities?

A. No. The Commission has already recognized that these type of costs need to be contained. It has also recognized that ratepayers should not be forced to fund an escalating competition between the electric and gas industry. Furthermore, initially any increased sales arising out of these marketing efforts accrue solely to shareholders. Ratepayers should not be required fund the cost of the Company's marketing and promotional activities. Accordingly, as shown on RLM-8, page 7, line 44, I have removed $2,892,434 from my recommended annualized payroll calculation.

Q. Please discuss the fifth element of the Company's labor adjustment.

A. The Company has used the test-year O&M ratio to determine the portion of the proforma labor that is expense and the portion that is capitalized.

Q. Do you agree with this element of the Company's proposed labor adjustment.

A. Yes. The test-year O&M ratio forms a reasonable basis for estimating the level of proforma labor that will be expensed. RUCO has no objection to the use of the test-year O&M ratio.

Q. Please summarize the specific adjustments you have made to the Company's proposed labor expense.

A. I have made the following adjustments:

1. Removed the projected 2005 wage and salary increase of 2.00%. The Company's annualization adjustment already includes the test-year labor increases;
2. Removed the projected post-test-year "within grade" wage increases. The test year has already been annualized to reflect the level of salaries and wages, including "within grade" increases, as of the test year end; and
3. Removed from the test-year annualized labor the amount related to sales and marketing payroll costs.

. . .

Since the Commission has previously disallowed the cost of sales, marketing and promotional activities.

Q. What are the elements of the Company's proposed labor loading expense adjustment?

A. The Company's proposed adjustment is comprised of the following elements:

1. Annualization of FICA, FUTA, SUTA and Medicare expenses;
2. Increase other employee benefits based on the annualized salaries and annualized employee levels; and
3. Remove expenses related to employee gifts, events and awards in compliance with Commission Decision No. 64172, dated October 30, 2001.

Q. Which of the Company's labor loading elements did you review and analyze for this adjustment?

A. In this adjustment I only considered the first element of the Company's adjustment to labor loading. The Company's second and third labor loading elements will be discussed later in my testimony.

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Q. What adjustments did you make to the Company's FICA, FUTA, SUTA and Medicare payroll taxes?

A. I adjusted the Company's FICA, FUTA, SUTA and Medicare payroll taxes to correspond to RUCO's recommended level of labor.

Q. Please explain how you quantified the necessary adjustment.

A. As shown on Schedule RLM-8, page 4, I multiplied RUCO's recommended level of labor by the statutory FICA, FUTA, SUTA and Medicare rates. Through this calculation I determined the necessary level of payroll taxes. To this amount I applied the Company's test year O&M ratio to determine the portion of the payroll taxes that will be recorded to expense. As shown on Line 30 of Schedule RLM-8, page 4, it is necessary to decrease the proforma level of FICA, FUTA, SUTA and Medicare payroll taxes by $575,452 to correspond to RUCO's recommended level of payroll expense.

This total adjustment to labor and labor loading decreased test-year expenses by:

$4,235,547.

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<u>SWG Operating Income Adjustment No. 5 – Uncollectibles Annualization</u>

Q. Please explain your analysis to annualize the Company's uncollectibles expense in account number 904.

A. The Company has adjusted its test-year uncollectibles expense based on its test-year adjusted level of revenues. Because I am not proposing any test-year revenue adjustments, likewise no adjustment is necessary to uncollectibles expense.

<u>SWG Operating Income Adjustment No. 6 – Promotional Expenses</u>

Q. Please explain the Company's proposed adjustment to the promotional expenses.

A. The Company removes expenses related to promotional marketing and advertising programs from the cost of service that have not been allowed.

<u>SWG Operating Income Adjustment No. 7 – American Gas Association ("AGA") Dues</u>

Q. During the test year did the Company pay dues to the American Gas Association?

A. Yes. SWG paid $384,566 for its membership with the AGA during the test year.

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Q. What is the AGA?

A. The AGA is a national trade association for natural gas distribution and transmission companies.

Q. Has RUCO proposed an adjustment to remove a portion of the AGA dues paid during the test year from cost of service?

A. Yes. In the Company's response to RUCO data request number 14.2 documentation was provided from the AGA/NARUC Oversight Committee Staff Agreement, which identifies each category of AGA expenditures and the percentage of the AGA's *annual expenditures* that were devoted to each category.

Q. Which categories of AGA activities should not be funded by ratepayers?

A. The AGA spent approximately 16% of its budget in the Communications category, which promotes the use of gas over other fuels. In the Company's adjustment number 6, SWG recognized the Commission has determined that these types of costs should not be borne by ratepayers and therefore has removed similar expenses from this application.

Q. Are there any other categories of AGA expenditures that should not be borne by ratepayers?

A. Yes. The Public Affairs category of expenditures should not be borne by ratepayers, because this provides members with information on legislative and regulatory developments; prepares testimony, comments, and filings regarding legislative and regulatory activities; lobbies on behalf of the industry.

Q. Why should this category of expenditures of the AGA be excluded from rates?

A. The category of Public Affairs should be excluded because it is utilized to represent the legislative interests of gas company stockholders. Further, lobbying expenses are typically reflected as below-the-line expenditures and not included in rates.

Q. What adjustment have you made?

A. As shown on Schedule RLM-9, I have removed 39.09% of the Arizona allocated portion of SWG's test year AGA dues. This represents the percentage of the AGA's expenditures that was used for advertising and lobbying.

This adjustment reduces operating expenses by:

$75,385.

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<u>SWG Operating Income Adjustment No. 9 – Paiute Allocation Annualization</u>

Q. Please explain your analysis to annualize the Company's Paiute Allocation in accounts numbered 920 and 930.

A. After review of the Company's Schedule C-2, Adjustment No. 9, I made no adjustment.

<u>SWG Operating Income Adjustment No. 10 – Injuries and Damages</u>

Q. Please explain your adjustment to the Company's injury and damage expenses.

A. The adjustment consists to two elements. First, the Company normalizes its self-insured retention costs, and second, the Company annualizes its liability insurance premiums.

Q. Please explain the first element of this adjustment to normalize the Company's estimated self-insured expense.

A. The Company proposes to use a fourteen-year average of actual claims paid to establish a level of self-insured expense.

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Q. Is there a problem with the Company's proposal to use of the fourteen-year average of actual claims paid to establish a level of self-insured expense?

A. Yes. Since the maximum deductible is now $10 million, I reduced the 1993 $18.8 million dollar claim to $10 million to reflect the new parameters.

Q. Please explain the second element of your analysis of the Company's adjustments to test-year liability insurance premiums.

A. After review of the Company's computations to amortize the liability insurance premiums on Schedule C-2, adjustment number 10, sheet 2, I made no changes to this portion of SWG's adjustment.

This total adjustment decreased test-year expenses by: $346,404.

SWG Operating Income Adjustment No. 13 – Rate Case Expense

Q. Please explain your review of the Company's proposed rate case expenses in account number 328.

A. Through the Company's response to RUCO data request 14.4 I have obtained copies of rate case billings to date, the total amount actually incurred is not yet known. Thus, the accuracy and reasonableness of the Company's estimated level of expense cannot be determined. As a result, at this time I am not proposing an adjustment to the rate case expense. RUCO however, reserves the right to change its position as more information becomes available.

SWG Operating Income Adjustment No. 14 – Miscellaneous Expenses

Q. Please explain your analysis of the Company's proposed adjustment to remove certain costs from test year expenses that the Company deems inappropriate to recover from these proceedings.

A After review of the Company's workpapers and its response to RUCO data requests numbered 5, 6, 8, 11, 12 and 14, I determined there were numerous similar type of expenditures not removed by the Company in its adjustment number 14.

Therefore, as shown on Schedule RLM-12, RUCO has made an additional adjustment to more accurately reflect the removal of test-year expenses related to payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service. Back-up documentation denoting each individual expense removed is recorded in my Workpaper Schedules: RLM-11WP(870) Pages 1 To 4, RLM-11WP(880) Pages 1 To 18, and RLM-11WP(902) Pages 1 To 3.

. . .

This adjustment decreased test-year expenses by: $346,299.

SWG Operating Income Adjustment No. 15 – Vehicle Compensation

Q. Please explain your analysis of the Company's adjustment to vehicle compensation expenses.

A. After review of the Company's calculation to remove the amount of test year expenses included in employee income for the personal use of Company vehicles, I made no adjustment.

SWG Operating Income Adjustment No. 16 – Out of Period Expenses

Q. Please explain your analysis of the Company's removal of out of period expenses.

A. After review of the Company's Schedule C-2, adjustment number 16, I made no adjustment.

SWG Operating Income Adjustment No. 18 – Property Tax

Q. Do you agree with SWG's methodology for computing gas utility property taxes?

A. Yes. I have used the same methodology to compute RUCO's recommended level of property taxes.

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. . .

This calculation is shown on Schedule RLM-13, the difference in the amount I have calculated versus the Company is solely a result of our respective levels of recommended net plant in service and our respective treatment of Contributions in Aid of Construction..

This adjustment decreased test-year expenses by:
$1,267,863.

SWG Operating Income Adjustment No. 19 – Interest on Customer Deposits

Q. Please explain your analysis of the Company's adjustment to the interest on customer deposits expense.

A. After review of the Company's Schedule C-2, adjustment number 19, I made no adjustment.

Operating Income Adjustment No. 20 – RUCO Adjustments To Operating Expenses

Q. Please explain the basis for the additional adjustments you made to the operating expenses.

A. For clarification purposes, I made separate adjustments to the Company's adjustment number 3.

. . .

. . .

These adjustments highlight specific issues embedded in SWG's payroll, which are included in the labor and labor loading costs and should not be the sole financial burden of the ratepayers.

Q. What specific adjustment do you recommend?

A. I made an adjustment to Supplemental Executive Retirement Plan costs.

Q. Please explain your adjustment to the Supplemental Executive Retirement Plan.

A. The Company's test-year payroll loadings include the cost of a Supplemental Executive Retirement Plan ("SERP"). The Company's test year operating expenses include approximately $2.7 million related to the SERP. The SERP is a retirement plan that is provided to a small select group of high-ranking officers of the Company. The high-ranking officers who are covered under the SERP receive these benefits in addition to the regular retirement plan.

Q. Should ratepayers be required to pay the cost of supplemental benefits for the high-ranking officers of the Company?

A. No. The cost of supplemental benefits for high-ranking officers is not a necessary cost of providing gas service. These individuals are already fairly compensated for their work and are provided with a wide array of benefits including a medical plan, dental plan, life insurance, long term disability, paid absence time, and a retirement plan. If the Company feels it is necessary to provide additional perks to a select group of employees it should do so at its own expense.

Q. In SWG's recent Nevada rate case, what did the Nevada Commission rule regarding SERP?

A. The Nevada Commission agrees SERP should be excluded from operating expenses; SWG has not presented any documentation or evidence to detail or support its SERP as reasonable.

Q. What adjustment are you recommending?

A. As shown on Schedule RLM-14, I have removed the test year cost of the SERP from operating expenses. This adjustment decreases operating expenses by $1,566,073.

RATE DESIGN

Q. Please explain your contribution to RUCO's recommended rate designs.

A. I was responsible to produce an accurate set of bill determinants (i.e. test-year customer bill counts and therms consumed). I revised the bill determinants to reflect an updated bill frequency analysis provide by the Company in its response to RUCO data request 9.01. I made further adjustments to correctly produce test-year revenues from these revised determinants. I then imputed the revised bill determinants into the

Company's proposed rate design; and finally annualized the imputed bill determinants by utilizing the Company's pro forma adjustments. Ms. Marylee Diaz Cortez will discuss RUCO's proposed rate design and structure in her testimony.

Q. Have you prepared a Schedule presenting your recommended bill determinants?

A. Yes, I have. My recommended bill determinants are an integral part of the rate design presented on Schedule RLM-16, pages 1 through 3.

PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that RUCO's recommended rate designs will produce the recommended required revenue as illustrated, is presented on Schedule RLM-16, page 3.

TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended rate design on the typical residential customer?

A. Yes, I have. A typical bill analysis for a metered residential customer is presented on Schedule RLM-17.

. . .

Q. Please explain elements of your typical bill analysis.

A. Schedule RLM-17 illustrates the elements proposed by Ms. Diaz Cortez in her testimony, which are:

1. Shift a portion of the revenue requirement that is currently recovered from the commodity rates to the fixed monthly charges;
2. Flatten the current declining tier commodity rate structure to one uniform commodity rate for all usage; and
3. Eliminate the summer and winter rate structure differential.

Q. Please provide an excerpt of RUCO's rate structure that illustrates these fundamental changes in SWG's current rate design.

A. Schedule RLM-17 provides an extensive breakdown of the effects of RUCO's proposed rates on the G-5 Residential Customer. Below is a chart gleaned from Schedule RLM-17 comparing SWG's present winter rates to RUCO's proposed annual rates:

<u>SWG Present Rates and Charges</u>

Basic Monthly Service Charge	$8.00
Commodity Charges (including both margin and a gas cost of $0.5346):	
Winter (October to May)	
First Tier (Up to 40 Therms)	$1.02198
Second Tier (Over 40 Therms)	$0.93780

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RUCO Proposed Rates and Charges

Basic Monthly Service Charge $9.36

Commodity Charges All Usage (including both margin and a gas cost of $0.5346) $1.021545

Description	Therms	Present	Proposed	$ Increase	% Increase
25% Average	11	$19.46	$20.81	$1.36	6.97%
75% Average	34	$42.37	$43.71	$1.35	3.18%
Average Usage	45	$53.41	$55.16	$1.75	3.27%
150% Average	67	$74.44	$78.06	$3.63	4.87%
200% Average	90	$95.46	$100.96	$5.50	5.76%

Q. Please indicate how this chart illustrates the first goal of RUCO's proposed rates.

A. As shown by the percentage increase of 6.97% for the minimal consumption customers (consuming only 25% of the average customer), this is the greatest percentage increase of all analyzed groups. This indicates a shift of the allocation of revenue from the variable usage component to the fixed basic service charge. This shift will afford the Company a better opportunity to recover its costs.

Q. Please indicate how this chart illustrates the second and third goals of RUCO's proposed rates.

A. As shown in RUCO's proposed rates and charges, the commodity charges have been simplified by recommending one year-round uniform commodity rate. This uniform rate eliminates the summer/winter differential and insures all customers within each rate structure will pay the same amount for each therm consumed. This uniform rate promotes SWG's corporate objective for energy efficient consumption over the Company's proposed declining rate. Moreover, as illustrated by the incrementally greater percentage increase for the higher consumers (i.e. 4.87% for consumption at 150% of average and 5.78% for consumption at 200%) provides a positive price signal to encourage energy efficient usage.

COST OF CAPITAL

Q. Is RUCO proposing any adjustments to the Company proposed cost of capital?

A. Yes, it is. This adjustment decreases the Company's cost of common equity and therefore its weighted cost of capital by 76 basis points from 9.40 to 8.64 percent to reflect current market conditions. This adjustment is fully explained in the testimony of RUCO witness William A. Rigsby.

CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations.

A. I conclude that the approval of this application will be consistent with the public interest if the Commission adopts the following recommendations:

1. For ratemaking purposes, the proposed revenue requirements should not exceed $370,818,589.

2. For ratemaking purposes, the FVRB for test year ending August 31, 2004 should be $1,163,910,949.
3. A fair and reasonable rate of return on FVRB is 6.82 percent.
4. Deny the Company's request for a CMT as a residential margin decoupling mechanism and in its stead utilize the rate structure as recommended by RUCO.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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Test Year Ended August 31, 2004

TABLE OF CONTENTS TO RUCO SCHEDULES

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) COMPANY RCND	(C) COMPANY FAIR VALUE	(D) RUCO ORIGINAL COST	(E) RUCO RCND	(F) RUCO FAIR VALUE
1	Adjusted Rate Base	$ 925,212,447	$ 1,417,642,156	$ 1,171,427,301	$ 918,447,207	$ 1,409,374,691	$ 1,163,910,949
2	Adjusted Operating Income (Loss)	$ 44,233,345	$ 44,233,345	$ 44,233,345	$ 50,445,135	$ 50,445,135	$ 50,445,135
3	Current Rate Of Return (Line 2 / Line 1)	4.78%	3.12%	3.78%	5.49%	3.58%	4.33%
4	Required Operating Income (Line 5 X Line 1)	$ 86,957,942	$ 86,957,942	$ 86,957,942	$ 79,378,637	$ 79,378,637	$ 79,378,637
5	Required Rate Of Return	9.40%	6.13%	7.42%	8.64%	5.63%	6.82%
6	Operating Income Deficiency (Line 4 - Line 2)			$ 42,724,598	$ 28,933,501		$ 28,933,501
7	Gross Revenue Conversion Factor (Schedule RLM-1, Page 2)			1.6573			1.6573
8	Increase In Gross Revenue Requirement (Line 7 X Line 6)			$ 70,809,128			$ 47,952,611
9	Adjusted Test Year Revenue			$ 322,865,978			$ 322,865,978
10	Proposed Annual Revenue Requirement (Line 8 + Line 9)			$ 393,675,106			$ 370,818,589
11	Required Percentage Increase In Revenue (Line 8 / Line 9)			21.93%			14.85%
12	Rate Of Return On Common Equity			11.95%			10.15%

References:
Columns (A) Thru (C): Company Schedule A-1, C-1 And D-1
Columns (D) Thru (F): Schedules RLM-2, RLM-5, RLM-6 And RLM-18

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GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	REFERENCE	(A)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:		
1	Revenue		1.0000
2	Less: Uncollectibles	Company Schedule C-2, Adjustment No. 5, Line 2, Column (b)	0.0022
3	Subtotal	Line 1 - Line 2	0.9978
4	Less: Combined Federal And State Tax Rate	Line 14	0.3944
5	Subtotal	Line 3 - Line 4	0.6034
6	**Revenue Conversion Factor**	Line 1 / Line 5	**1.6573**
	CALCULATION OF EFFECTIVE TAX RATE:		
7	Arizona Taxable Income		1.0000
8	Arizona State Income Tax Rate		0.0697
9	Federal Taxable Income	Line 7 - Line 8	0.9303
10	Applicable Federal Income Tax Rate		0.3500
11	Effective Federal Income Tax Rate	Line 9 X Line 10	0.3256
12	Subtotal	Line 8 + Line 11	0.3953
13	Revenue Less Uncollectibles	Line 3	0.9978
14	Combined Federal And State Income Tax Rate	Line 12 X Line 13	0.3944

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RATE BASE - ORIGINAL COST

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS OCRB	(B) RUCO OCRB ADJUSTMENTS	REF.	(C) RUCO ADJUSTED AS OCRB
1	Gas Plant In Service	$1,685,504,145	$ (4,428,513)	(1)	$ 1,681,075,632
	Less:				
2	Accumulated Depreciation And Amortization	593,542,006	(1,089,621)	(1)	592,452,385
3	Net Gas Plant In Service (Line 1 - Line 2)	$1,091,962,139	$ (3,338,892)		$ 1,088,623,247
	Additions:				
4	Allowance For Working Capital (MDC-3, Page 1)	$ 881,148	$ (3,649,600)	(2)	$ (2,768,452)
5	Total Additions (Line 4)	$ 881,148	$ (3,649,600)		$ (2,768,452)
	Deductions:				
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -		$ (7,027,372)
7	Customer Deposits	(23,912,141)	-		(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(3)	(136,468,076)
9	Total Deductions (Sum Of Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252		$ (167,407,589)
10	TOTAL ORIGINAL COST RATE BASE (Sum Of Lines 3, 5 & 9)	$ 925,212,447	$ (6,765,240)		$ 918,447,207

References:
Column (A): Company Schedule B-1
Column (B):
(1) Schedule RLM-3
(2) Schedule MDC-3
(3) Schedule MDC-1
Column (C): Column (A) + Column (B)

Southwest Gas Corporation
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Test Year Ended August 31, 2004

"DIRECT" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				COMPANY TEST YEAR AS FILED		ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP.	PIPE SUR'Y/REP'R	PIPE SUR/REP ACC. DEP.	CCNC NET ADDITIONS	ACC DEP CCNC ADDITIONS	ACC DEP CCNC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP. INT'G ADDITIONS	ACC. DEP. INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	Amor'd	$ 42,653	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 42,653	$ -	$ 42,653
2	302.0	Franchises & Consents	Amor'd	1,714,402	529,246	-	-	-	-	-	-	-	-	-	1,714,402	529,246	1,185,156
3	303.0	Miscellaneous Intangible	Amor'd	1,945,631	1,667,452	-	-	-	-	-	-			-	1,945,631	1,667,452	278,179
4		Total Intangible Plant		$ 3,702,686	$ 2,196,698	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,702,686	$ 2,196,698	$ 1,505,988
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ 351,685	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 351,685	$ -	$ 351,685
6	374.2	Rights Of Way	2.15%	720,979	274,994	-	-	-	-	-	-	-	-	-	720,979	274,994	445,985
7	375.0	Structures	1.15%	110,557	62,874	3,923	-	-	-	-	-	-	-	-	110,557	66,797	43,760
8	376.0	Mains	3.82%	789,647,065	273,373,290	-	(1,224,119)	(72,387)	(1,485,395)	6,390	40,038	-	-	-	786,937,551	273,267,255	513,670,296
9	378.0	Measuring & Regulating Station	4.12%	24,454,990	1,274,807	-	-	-	-	-	-	-	-	-	24,454,990	1,274,807	23,180,183
10	380.0	Services	5.30%	523,802,714	218,592,143	-	(1,115,660)	(61,455)	-	-	-	-	-	-	522,687,054	218,530,688	304,156,366
11	381.0	Meters	1.98%	156,809,964	30,981,761	-	-	-	-	-	-	-	-	-	156,809,964	30,981,761	125,828,203
12	385.0	Industrial Measuring & Reg. Station	4.31%	6,528,499	2,586,375	-	-	-	-	-	-	-	-	-	6,528,499	2,586,375	3,942,124
13	387.0	Other Equipment	5.26%	462,730	502,185	14,288	-	-	-	-	-	-	-	-	462,730	516,473	(53,743)
14		Total Distribution Plant		$1,502,889,183	$ 527,648,429	$ 18,211	$ (2,339,779)	$ (133,842)	$ (1,485,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,499,064,009	$ 527,499,150	$ 971,564,859
		General Plant:															
15	389.0	Land & Land Rights	N/A	$ 6,454,589	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 6,454,589	$ -	$ 6,454,589
16	390.1	Structures	1.84%	26,285,123	7,274,350	-	-	-	-	-	-	-	-	-	26,285,123	7,274,350	19,010,773
17	390.2	Structures - Leasehold Improv'ts	Amor'd	1,005,567	599,757	37,893	-	-	-	-	-	-	-	-	1,005,567	637,650	367,917
18	391.0	Office Furniture And Equipment	2.73%	4,849,827	656,607	-	-	-	-	-	-	-	-	-	4,849,827	656,607	4,193,220
19	391.1	Computer Equipment	14.87%	8,489,038	1,178,796	-	-	-	-	-	-	-	-	-	8,489,038	1,178,796	7,310,242
20	392.1	Transportation Equipment	7.65%	30,447,147	5,293,542	-	-	-	-	-	-	-	-	-	30,447,147	5,293,542	25,153,605
21	393.0	Stores Equipment	2.08%	481,909	14,058	-	-	-	-	-	-	-	-	-	481,909	14,058	467,851
22	394.0	Tools, Shop And Garage Equip.	2.17%	4,891,998	(2,642,962)	-	-	-	-	-	-	-	-	-	4,891,998	(2,642,962)	7,534,960
23	395.0	Laboratory Equipment	3.93%	425,322	(150,109)	-	-	-	-	-	-	-	-	-	425,322	(150,109)	575,431
24	396.0	Power Operated Equipment	3.88%	3,807,547	1,118,830	-	-	-	-	-	-	-	-	-	3,807,547	1,118,830	2,688,717
25	397.0	Communication Equipment	8.88%	2,223,684	2,332,366	-	-	-	-	-	-	-	-	-	2,223,684	2,332,366	(108,682)
26	397.2	Telemetering Equipment	6.19%	560,307	432,184	-	-	-	-	-	-	-	-	-	560,307	432,184	128,123
27	398.0	Miscellaneous Equipment	4.53%	844,186	32,818	78	-	-	-	-	-	-	-	-	844,186	32,896	811,290
28		Total General Plant		$ 90,766,244	$ 16,140,237	$ 37,971	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 90,766,244	$ 16,178,208	$ 74,588,036
29		TOTAL DIRECT PLANT		$1,597,358,113	$ 545,985,364	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,485,395)	$ 6,390	$ 40,038	$ -	$ -	$ -	$ 1,593,532,939	$ 545,874,056	$1,047,658,883
30		Allocated Plant (See RLM-3, Page 2, Line 31)		88,146,035	47,556,640	-	-		(116,232)	(12,297)	-	(487,110)	(81,104)	884,911	87,542,693	46,578,329	40,964,364
31		TOTAL PLANT		$1,685,504,148	$ 593,542,004	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (487,110)	$ (81,104)	$ 884,911	$ 1,681,075,632	$ 592,452,385	$1,088,623,247
32		Direct Plant As Per Company		$1,597,358,113	$ 545,985,364	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,597,358,113	$ 545,985,364	1,051,372,749
		Common Plant As Per Company		88,146,035	47,556,640	-	-	-	-	-	-	-	-	-	88,146,035	$ 47,556,640	40,589,394
33		Difference		$ -	$ -	$ 56,182	$ (2,339,779)	$ (133,842)	$ (1,601,627)	$ (5,907)	$ 40,038	$ (487,110)	$ (81,104)	$ 884,911	$ (4,428,516)	$ (1,089,619)	$ (3,338,896)

References:
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

"SYSTEM ALLOCABLE" TEST YEAR PLANT SCHEDULES
YEAR ENDED AUGUST 31, 2004

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)
				COMPANY TEST YEAR AS FILED		ADJ. NO. 1	ADJ. NO. 2		RUCO ADJUSTMENT NO. 3			RUCO ADJUSTMENT NO. 4			RUCO AS ADJUSTED		
LINE NO.	ACCT NO.	ACCOUNT NAME	DEP RATE	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	RUCO DR 7.01(C) ACC. DEP.	PIPE SUR'Y/REP'R	PIPE SUR/REP ACC. DEP.	CCNC NET ADDITIONS	ACC DEP CCNC ADDITIONS	ACC DEP CCNC RETIREMENTS	MISC INT'GIBLE NET PLANT	ACC. DEP. INT'G ADDITIONS	ACC. DEP. INT'G RETIREMENTS	TOTAL PLANT VALUE	ACCUMULATED DEPRECIATION	NET PLANT VALUE
		Intangible Plant:															
1	301.0	Organization	0.00%	$ 61,816	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 61,816	$ -	$ 61,816
2	302.0	Franchises & Consents	Amor'd	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	303.0	Miscellaneous Intangible	Amor'd	106,174,215	60,385,073	-	-	-	-	-	-	(845,975)	(140,855)	1,536,844	105,328,240	58,707,374	46,620,866
4		Total Intangible Plant		$ 106,236,031	$ 60,385,073	$ -	$ -	$ -	$ -	$ -	$ -	$ (845,975)	$ (140,855)	$ 1,536,844	$ 105,390,056	$ 58,707,374	$ 46,682,682
		Distribution Plant:															
5	374.1	Land & Land Rights	N/A	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	374.2	Rights Of Way	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	375.0	Structures	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
8	376.0	Mains	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
9	378.0	Measuring & Regulating Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
10	380.0	Services	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
11	381.0	Meters	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
12	385.0	Industrial Measuring & Reg. Station	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
13	387.0	Other Equipment	N/A	-	-	-	-	-	-	-	-	-	-	-	-	-	-
14		Total Distribution Plant		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		General Plant:															
15	389.0	Land & Land Rights	0.00%	$ 391,307	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 391,307	$ -	$ 391,307
16	390.1	Structures	2.46%	11,831,108	3,565,211	-	-	-	-		-	-	-	-	11,831,108	3,565,211	8,265,897
17	390.2	Structures - Leasehold Improv'ts	Amor'd	3,144,329	2,895,028	-	-	-	-	-	-	-	-	-	3,144,329	2,895,028	249,301
18	391.0	Office Furniture And Equipment	3.99%	7,755,795	1,861,177	-	-	-	(4,145)	(83)	-	-	-	-	7,751,650	1,861,094	5,890,556
19	391.1	Computer Equipment	30.01%	13,573,926	10,549,263	-	-	-	(128,028)	(19,211)	-	-	-	-	13,445,898	10,530,052	2,915,846
20	392.1	Trans. Equip. - Light Vehicles	6.42%	3,389,404	1,095,677	-	-	-	(50,507)	(1,621)	-	-	-	-	3,338,897	1,094,056	2,244,841
21	393.0	Trans. Equip. - Heavy Vehicles	6.42%	111,293	(34,504)	-	-	-	-	-	-	-	-	-	111,293	(34,504)	145,797
22	394.0	Stores Equipment	4.45%	24,106	(5,005)	-	-	-	(16,720)	(372)	-	-	-	-	7,386	(5,377)	12,763
23	395.0	Tools, Shop And Garage Equip.	4.10%	414,693	(29,696)	-	-	-	-	-	-	-	-	-	414,693	(29,696)	444,389
24	396.0	Laboratory Equipment	3.05%	268,894	82,474	-	-	-	-	-	-	-	-	-	268,894	82,474	186,420
25	397.0	Communication Equipment	9.88%	4,605,689	2,519,905	-	-	-	-	-	-	-	-	-	4,605,689	2,519,905	2,085,784
26	397.2	Telemetering Equipment	20.38%	401,430	(186,565)	-	-	-	-	-	-	-	-	-	401,430	(186,565)	587,995
27	398.0	Miscellaneous Equipment	5.65%	937,148	(105,377)	-	-	-	(2,462)	(70)	-	-	-	-	934,686	(105,447)	1,040,133
28		Total General Plant		$ 46,849,122	$ 22,207,588	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ -	$ -	$ -	$ 46,647,260	$ 22,186,232	$ 24,461,028
29		TOTAL ALLOCABLE PLANT		$ 153,085,153	$ 82,592,661	$ -	$ -	$ -	$ (201,862)	$ (21,356)	$ -	$ (845,975)	$ (140,855)	$ 1,536,844	$ 152,037,316	$ 80,893,606	$ 71,143,710
30		Allocation Factor		57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%	57.58%
31		TOTAL ALLOCATE PLANT		$ 88,146,035	$ 47,556,640	$ -	$ -	$ -	$ (116,232)	$ (12,297)	$ -	$ (487,110)	$ (81,104)	$ 884,911	$ 87,542,693	$ 46,578,329	$ 40,964,364

References:
Columns (A) (B) (C): Company Workpapers B-2, Sheets 1 Through 8 And C-2, Adjustment 17, Sheets 1 Through 5
Column (D): Company Response To RUCO Data Request 7.01(C)
Columns (E) (F): See Testimony, MDC
Columns (G) (H) (I): See Schedule RLM-4, Pages 1 & 2
Columns (J) (K) (L): See Testimony, MDC
Column (M): Sum Of Cols. (B) (E) (G) (J)
Column (N): Sum Of Cols. (C) (D) (F) (H) (K) - Minus Cols. (I) (L)
Column (O): Column (M) - Column (N)

Southwest Gas Corporation
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EXPLANATION OF SWG TEST-YEAR PLANT ADJUSTMENT NO. 20
ARIZONA DIRECT - COMPLETED CONSTRUCTION NOT CLASSIFIED

LINE NO.	ACCT. NO.	DESCRIPTION	(A) CONST. WK ORDER	(B) RETIRE'T WK ORDER	(C) IN-SER. DATE	(D) ACTUAL CONST. COST	(E) ACTUAL RETIRE'T COST
		DISTRIBUTION PLANT					
	376.0	Mains					
1		Replace 1960' of 1 1/2" Steel	C3662360	R3662360	Jul-04	$ 50,393	$ (3,309)
2		Replace 276' of 2"PVC	C3681448	R3681448	Jan-04	16,540	(209)
3		Replace Approximately 1800'	C4262016	R4262016	Aug-04	103,420	-
4		Replace 195' of 2" Drisco	C2585555	R2585555	Jul-04	5,974	(1,941)
5		Relocate Exisitng 4" Steel	C4264224	R4264224	Aug-04	2,646	(16,369)
6		Replace 2" Srisco Main	C4269542	R4269542	Jul-04	525	(2,295)
7		Replace 538' of 2"PE800	C4274671	R4274671	Aug-04	(572)	(5,222)
8		Instal 138' of 4" PE Main	C3660167	R3660167	May-04	26,546	(1,492)
9		Abandon 2995'	C3693590	R3693590	Aug-04	68,349	(9,201)
10		Inbstall 307' of 2" Steel Main	C3213815	R3213815	Aug-04	21,553	-
11		Install 624' of 4" PE Main	C4236882		Aug-04	49,998	-
12		Install 844' of 2" PE Main	C4239280		Aug-04	29,220	-
13		SUBTOTAL DISTRIBUTION PLANT				$ 374,592	$ (40,038)
14		RUCO RECOMMENDED NET ARIZONA DIRECT CCNC					$ 334,554
15		Company As Filed					1,819,949
16		RUCO ADJUSTMENT TO ARIZONA DIRECT CCNC					$(1,485,395)

Reference
Columns (A) (B) (C) (D) (E): Company Response To RUCO Date Request No. 13

Southwest Gas Corporation
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EXPLANATION OF SWG TEST-YEAR PLANT ADJUSTMENT NO. 20 - CONT'D
SYSTEM ALLOCABLE - COMPLETED CONSTRUCTION NOT CLASSIFIED

LINE NO.	ACCT. NO.	DESCRIPTION	(A) CONST. WK ORDER	(B) RETIRE'T WK ORDER	(C) IN-SER. DATE	(D) ACTUAL CONST. COST	(E) RUCO ADJUSTM'T
		GENERAL PLANT					
	391.0	Office Furniture & Equipment					
1		Purchase a Shrink Wrap Machine	C4100077		Aug-04	$ 8,162	
2		Purchase a Stretch Wrap Machine	C4100026		Jan-05	Outside TY	
3		Subtotal Office Furniture & Furniture				$ 8,162	
5		RUCO Recommended Net Arizona System Allocated CCNC				$ 8,162	
6		Company As Filed				12,307	
7		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 391.0					$ (4,145)
	391.1	Computer Equipment					
8		Purchase 60 Itron Terminals	C4100044		Not In Service	Outside TY	
9		Purchase IP530 Base System	C4100088		Nov-04	Outside TY	
10		Purchase Bowe Bell & Howell H. Total Controll	C4100073		Not In Service	Outside TY	
11		Subtotal Computer Equipment				$ -	
13		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
14		Company As Filed				$ 128,028	
15		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 391.1					$(128,028)
	392.1	Transportation Equipment					
16		Purchase 1 Cheverolet Trailbazer	C4100089		Nov-04	Outside TY	
17		Purchase 2005 Explorer/4546	C4100097		Nov-04	Outside TY	
18		Subtotal Transportation Equipment				$ -	
20		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
21		Company As Filed				$ 50,507	
22		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 392.1					$ (50,507)
	394.0	Tools, Shop, & Garage Equipment					
23		Purchase Chlor-rid Soil Testers	C4100083		Sep-04	Outside TY	
24		Purchase Wirescope Testers	C4100082		Jan-05	Outside TY	
25		Subtotal Tools, Shop, & Grarage Equipment				$ -	
27		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
28		Company As Filed				$ 16,720	
29		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 394.0					$ (16,720)
	398.0	Miscellaneous Equipment					
30		Purchase OSS Projector	C4100096		Oct-04	Outside TY	
31		Subtotal Miscellaneous Equipment				$ -	
32		RUCO Recommended Net Arizona System Allocated CCNC				$ -	
33		Company As Filed				$ 2,462	
34		RUCO ADJUSTMENT TO SYSTEM ALLOCABLE CCNC IN ACCOUNT 398.0					$ (2,462)

Reference
Columns (A) (B) (C) (D) (E): Company Response To RUCO Date Request No. 13

Southwest Gas Corporation
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RATE BASE - RECONSTRUCTED COST NEW DEPRECIATED

LINE NO.	DESCRIPTION	(A) COMPANY FILED AS RCND	(B) RUCO RCND ADJUSTMENTS	(C) RUCO ADJUSTED AS RCND
1	Gas Plant In Service	$ 2,441,205,028	$ (6,414,050)	$ 2,434,790,978
	Less:			
2	Accumulated Depreciation And Amortization	856,813,179	(1,572,933)	855,240,246
3	Net Gas Plant In Service (Line 1 - Line 2)	$ 1,584,391,849	$ (4,841,117)	$ 1,579,550,732
	Additions:			
4	Allowance For Working Capital	$ 881,148	$ (3,649,600)	$ (2,768,452)
5	Total Additions (Line 4)	$ 881,148	$ (3,649,600)	$ (2,768,452)
	Deductions:			
6	Customer Advances In Aid Of Construction	$ (7,027,372)	$ -	$ (7,027,372)
7	Customer Deposits	(23,912,141)	-	(23,912,141)
8	Deferred Income Taxes	(136,691,328)	223,252	(136,468,076)
9	Total Deductions (Sum Lines 6, 7 & 8)	$ (167,630,841)	$ 223,252	$ (167,407,589)
10	TOTAL RCND RATE BASE	$ 1,417,642,156	$ (8,267,465)	$ 1,409,374,691

References:

Column (A): Company Schedule B-1
Column (B): Column (C) - Column (A)
Column (C): OCRB (RLM-2, Column (C)) X Same Ratio As The Company's RCND Is To Its OCRB (144.84%)

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJ'TMENTS	(C) RUCO TEST YEAR AS ADJUSTED	(D) RUCO PROPOSED CHANGES	(E) RUCO AS RECOMMENDED
1	Revenues	$ 322,865,978	$ -	$ 322,865,978	$ 47,952,611	$ 370,818,589
2	Gas Cost	-	-	-	-	-
3	TOTAL MARGIN	$ 322,865,978	$ -	$ 322,865,978	$ 47,952,611	$ 370,818,589
	EXPENSES:					
4	Other Gas Supply	$ 740,391	$ (21,030)	$ 719,361	$ -	$ 719,361
5	Distribution	78,580,466	(4,781,849)	73,798,617	-	73,798,617
6	Customer Accounts	34,003,279	(1,500,922)	32,502,357	-	32,502,357
7	Customer Information	548,496	(16,820)	531,676	-	531,676
8	Sales	-	-	-	-	-
	Administration & General					
9	Direct	6,993,300	(83,723)	6,909,577	-	6,909,577
10	System Allocable	45,487,895	(3,977,019)	41,510,876	-	41,510,876
	Depreciation & Amortization					
11	Direct	67,338,861	(109,637)	67,229,224	-	67,229,224
12	System Allocable	7,062,583	(123,789)	6,938,794	-	6,938,794
13	Regulatory Amortizations	1,548,204	(1,044,968)	503,236	-	503,236
14	Other Taxes	33,455,124	(1,267,863)	32,187,261	-	32,187,261
15	Interest On Cust. Deposits	717,364	-	717,364	-	717,364
16	Income Taxes	2,156,664	6,715,836	8,872,500	19,019,109	27,891,609
17	TOTAL EXPENSES	$ 278,632,626	$ (6,211,784)	$ 272,420,843	$ 19,019,109	$ 291,439,952
18	NET INCOME (LOSS)	$ 44,233,351		$ 50,445,135		$ 79,378,637

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-7
Column (C): Column (A) + Column (B)
Column (D): Testimony, RLM And Schedule RLM-1, Pages 1 & 2
Column (E): Column (C) + Column (D)

Southwest Gas Corporation
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) LEFT BLANK	(C) ADJ #3	(D) LEFT BLANK	(E) ADJ #7	(F) ADJ #8	(G) ADJ #10	(H) ADJ #12	(I) ADJ #14
1	Revenues	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$322,865,978	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	EXPENSES:									
4	Other Gas Supply	$ 740,391	$ -	$ (11,215)	$ -	$ -	$ -	$ -	$ -	$ -
5	Distribution	78,580,466	-	(2,369,584)	-	-	-	-	(1,488,287)	(188,165)
6	Customer Accounts	34,003,279	-	(1,109,837)	-	-	-	-	-	(10,715)
7	Customer Information	548,496	-	(12,880)	-	-	-	-	-	-
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	6,993,300	-	(31,720)	-	-	-	-	-	-
10	System Allocable	45,487,895	-	(700,309)	-	(75,385)	240,016	(346,404)		(147,419)
	Depreciation & Amortization									
11	Direct	67,338,861	-	-	-	-	-	-	-	-
12	System Allocable	7,062,583	-	-	-	-	(12,932)	-	-	-
13	Regulatory Amortizations	1,548,204	-	-	-	-	-	-	(1,044,968)	-
14	Other Taxes	33,455,124	-	-	-	-	-	-	-	-
15	Interest On Cust. Deposits	717,364	-	-	-	-	-	-	-	-
16	Income Taxes	2,156,664	-	-	-	-	-	-	-	-
17	TOTAL EXPENSES	$278,632,627	$ -	$ (4,235,547)	$ -	$ (75,385)	$ 227,084	$ (346,404)	$ (2,533,255)	$ (346,299)
18	NET INCOME (LOSS)	$ 44,233,351								

Adjustment No.:	References:
1 - Left Blank	
3 - Labor And Labor Loading Annualization	Testimony, RLM And Schedule RLM-8, Pages 1 To 7
4 - Left Blank	
7 - Amercian Gas Association ("AGA") Dues	Testimony, RLM And Schedule RLM-9, Page 1
8 - Sarbanas-Oxley Section 404 Compliance	Testimony, MDC And Schedule MDC-4
10 - Injuries And Damages	Testimony, RLM And Schedule RLM-10, Page 1
12 - Transmission Integrity Management Program	Testimony, MDC And Schedule MDC-5
14 - Miscellaneous Adjustments	Testimony, RLM And Schedule RLM-11, Page 1

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Schedule RLM-7
Page 2 of 2

SUMMARY OF OPERATING INCOME ADJUSTMENTS - CONT'D
TEST YEAR AS FILED AND ADJUSTED

LINE NO.	DESCRIPTION	(J) ADJ #17	(K) ADJ #18	(L) ADJ #20	(M) ADJ #21	(N) LEFT BLANK	(O) LEFT BLANK	(P) LEFT BLANK	(Q) INCOME TAX	(R) RUCO AS AD'TED
1	Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
2	Gas Cost	-	-	-	-	-	-	-	-	-
3	TOTAL MARGIN	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$322,865,978
	EXPENSES:									
4	Other Gas Supply	$ -	$ -	$ -	$ (9,815)	$ -	$ -	$ -	$ -	$ 719,361
5	Distribution	-	-	-	(735,813)	-	-	-	-	73,798,617
6	Customer Accounts	-	-	-	(380,369)	-	-	-	-	32,502,357
7	Customer Information	-	-	-	(3,939)	-	-	-	-	531,676
8	Sales	-	-	-	-	-	-	-	-	-
	Administration & General									
9	Direct	-	-	-	(52,003)	-	-	-	-	6,909,577
10	System Allocable	-	-	(2,563,384)	(384,133)	-	-	-	-	41,510,876
	Depreciation & Amortization									
11	Direct	(109,637)	-	-	-	-	-	-	-	67,229,224
12	System Allocable	(110,857)	-	-	-	-	-	-	-	6,938,794
13	Regulatory Amortizations	-	-	-	-	-	-	-	-	503,236
14	Other Taxes	-	(1,267,863)	-	-	-	-	-	-	32,187,261
15	Interest On Cust. Deposits	-	-	-	-	-	-	-	-	717,364
16	Income Taxes	-	-	-	-	-	-	-	6,715,836	8,872,500
17	TOTAL EXPENSES	$ (220,495)	$ (1,267,863)	$ (2,563,384)	$ (1,566,073)	$ -	$ -	$ -	$ 6,715,836	$272,420,843
18	NET INCOME (LOSS)									$ 50,445,135

Adjustment No.:	*References:*
17 - Deprecitation/Amortization Expense	Testimony, RLM, Schedule RLM-12, Pages 1 & 2 and Schedule MDC-6
18 - Property Tax Expense	Testimony, RLM And Schedule RLM-13, Page 1
20 - RUCO Adjustment To Management Incentive Plan	Testimony, MDC
21 - RUCO Adjustment To SERP	Testimony, RLM And Schedule RLM-14, Page 1
22 - Left Blank	
23 - Left Blank	
24 - Left Blank	
25 - RUCO Adjustment To Income Tax	Testimony, RLM And Schedule RLM-15, Page 1

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3
LABOR AND LABOR LOADING ADJUSTMENT

		(A)	(B)	(C)
		RUCO AS ADJUSTED		
LINE NO.	ARIZONA ACOUNT NUMBERS	LABOR (See RLM-8, Page 2, Col. (I)	LOADING (See RLM-8, Page 2, Col. (J)	TOTAL (Sum Of Columns (A) And (B)
	OPERATIONS			
1	813	$ 455,832	$ 216,139	$ 671,971
2	851	-	-	-
3	870	4,517,245	2,470,143	6,987,388
4	871	353,390	168,755	522,145
5	874	3,218,183	1,765,741	4,983,924
6	875	1,209,635	662,867	1,872,502
7	878	3,567,456	1,958,862	5,526,318
8	879	4,214,601	2,316,642	6,531,243
9	880	3,878,484	2,122,265	6,000,748
10	901	2,198,811	1,209,060	3,407,871
11	902	3,158,586	1,732,697	4,891,282
12	903	11,035,752	5,836,032	16,871,784
13	905	229,622	125,856	355,478
14	908	169,558	93,031	262,589
15	909	-	-	-
16	910	483	254	737
17	920	29,532,138	14,034,893	43,567,031
18	922	-	-	-
19	930	29,401	13,956	43,357
20	SUBTOTAL	$ 67,769,176	$ 34,727,192	$ 102,496,368
	MAINTENANCE			
21	885	$ 1,466,021	$ 802,355	$ 2,268,376
22	886	8,442	4,598	13,040
23	887	4,620,011	2,533,733	7,153,744
24	889	688,420	377,577	1,065,997
25	892	3,272,834	1,796,791	5,069,625
26	893	694,134	379,992	1,074,126
27	894	92,652	50,652	143,303
28	CORPORATE DIRECT 935	418,785	229,510	648,295
	SYSTEM ALLOCABLE 935	181,977	86,925	268,902
29	SUBTOTAL	$ 11,261,299	$ 6,175,207	$ 17,705,408
30	TOTALS	$ 79,030,475	$ 40,902,400	$ 120,201,776
	FUNCTIONALIZATION			
		COMPANY AS FILED (WP, ADJ. 3, Pg 11 Thru 24)	RUCO AS ADJUSTED (From Col. (C), Lines 1 To 29)	ADJUSTMENT (Col. (B) - (A)) (See RLM-7, Page 1, Col. (C))
31	OTHER GAS SUPPLY (813)	$ 683,186	$ 671,971	$ (11,215)
32	DISTRIBUTION (870-880 & 885-894)	51,582,063	49,212,479	(2,369,584)
33	CUST. ACC'TS (901, 902, 903 & 905)	26,636,254	25,526,417	(1,109,837)
34	CUST. SER. & INFO (908, 909, & 910)	276,206	263,326	(12,880)
35	SALES			
	ADMINISTRATION & GENERAL			
36	CORPORATE DIRECT (935)	680,015	648,295	(31,720)
37	SYS. ALLOC. (920, 922, 930 & 935)	44,579,599	43,879,290	(700,309)
38	TOTAL	$ 124,437,323	$ 120,201,776	$ (4,235,547)
39	RUCO ADJUSTMENT TO LABOR AND LABOR LOADING (See RLM-7, Page 1, Col (C), Line17)			$ (4,235,547)

References:
Columns (A) (B) (C): Calculated From The Following 6 Pages Of Schedule RLM-8

Southwest Gas Corporation
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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR AND LOADING PER RUCO ADJUSTMENTS

LINE	ACCT	(A) ARIZONA	(B)	(C) CORPORATE DIRECT	(D)	(E) TOTAL DIRECT	(F)	(G) SYSTEM ALLOCATED	(H)	(I) TOTAL ANNUALIZATION	(J)
		LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING	LABOR	LOADING
NO.	NO.	RLM-8, P5, (C)	RLM-8, P6, (C)	RLM-8, P5, (F)	RLM-8, P6, (F)	Col. (A) + (C)	Col. (B) + (D)	RLM-8, P5, (I)	RLM-8, P6, (I)	Col. (E) + (G)	Col. (F) + (H)
	OPERATIONS										
1	813	$ -	$ -	$ 455,832	$ 216,139	$ 455,832	$ 216,139	$ -	$ -	$ 455,832	$ 216,139
2	851	-	-	-	-	-	-	-	-	-	-
3	870	4,217,298	2,310,497	299,947	159,646	4,517,245	2,470,143	-	-	4,517,245	2,470,143
4	871	11,559	6,270	341,832	162,484	353,390	168,755	-	-	353,390	168,755
5	874	3,218,183	1,765,741	-	-	3,218,183	1,765,741	-	-	3,218,183	1,765,741
6	875	1,209,635	662,867	-	-	1,209,635	662,867	-	-	1,209,635	662,867
7	878	3,567,456	1,958,862	-	-	3,567,456	1,958,862	-	-	3,567,456	1,958,862
8	879	4,214,601	2,316,642	-	-	4,214,601	2,316,642	-	-	4,214,601	2,316,642
9	880	3,850,637	2,109,507	27,847	12,758	3,878,484	2,122,265	-	-	3,878,484	2,122,265
10	901	2,198,811	1,209,060	-	-	2,198,811	1,209,060	-	-	2,198,811	1,209,060
11	902	3,158,586	1,732,697	-	-	3,158,586	1,732,697	-	-	3,158,586	1,732,697
12	903	8,148,433	4,466,708	1,335,013	631,290	9,483,445	5,097,998	1,552,307	738,034	11,035,752	5,836,032
13	905	229,622	125,856	-	-	229,622	125,856	-	-	229,622	125,856
14	908	169,558	93,031	-	-	169,558	93,031	-	-	169,558	93,031
15	909	-	-	-	-	-	-	-	-	-	-
16	910	483	254	-	-	483	254	-	-	483	254
17	920	-	-	-	-	-	-	29,532,138	14,034,893	29,532,138	14,034,893
18	922	-	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,401	13,956	29,401	13,956
20	SUBTOT	$ 34,194,861	$ 18,757,991	$ 2,460,470	$ 1,182,317	$ 36,655,331	$ 19,940,309	$ 31,113,845	$ 14,786,884	$ 67,769,176	$ 34,727,192
	MAINTENANCE										
21	885	$ 1,364,675	$ 748,644	$ 101,347	$ 53,711	$ 1,466,021	$ 802,355	$ -	$ -	$ 1,466,021	$ 802,355
22	886	8,442	4,598	-	-	8,442	4,598	-	-	8,442	4,598
23	887	4,620,011	2,533,733	-	-	4,620,011	2,533,733	-	-	4,620,011	2,533,733
24	889	688,420	377,577	-	-	688,420	377,577	-	-	688,420	377,577
25	892	3,272,834	1,796,791	-	-	3,272,834	1,796,791	-	-	3,272,834	1,796,791
26	893	694,134	379,992	-	-	694,134	379,992	-	-	694,134	379,992
27	894	92,652	50,652	-	-	92,652	50,652	-	-	92,652	50,652
28	935	418,785	229,510	-	-	418,785	229,510	181,977	86,925	600,762	316,435
29	SUBTOT	$ 11,159,952	$ 6,121,496	$ 101,347	$ 53,711	$ 11,261,299	$ 6,175,207	$ 181,977	$ 86,925	$ 11,443,275	$ 6,262,132
30	O & M	$ 45,354,813	$ 24,879,488	$ 2,561,817	$ 1,236,028	$ 47,916,630	$ 26,115,516	$ 31,295,822	$ 14,873,809	$ 79,212,451	$ 40,989,325

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANNUALIZED LABOR

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
1	ANNUALIZED SALARY (WP C-2, ADJ. 3, SH 3)	$ 61,779,296	$ 2,843,265	$ 36,475,304	
	LESS:				
2	SALES/MARK'G DISALLOWANCE (RLM-8, Pg 7)	(2,125,266)	-	(767,168)	
3	SUBTOTAL (Line 1 + Line 2)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
	PLUS:				
4	2005 WAGES INCREASE % (See Testimony, RLM)	0.00%	0.00%	0.00%	
5	2005 WAGE INCREASE (Line 3 X Line 4)	$ -	$ -	$ -	
6	SUBTOTAL (Line 3 + Line 5)	$ 59,654,030	$ 2,843,265	$ 35,708,136	
7	OVERTIME % (WP C-2, ADJ. 3, SH 4)	8.53%	2.77%	0.43%	
8	OVERTIME (Line 6 X Line 7)	$ 5,090,722	$ 78,790	$ 154,180	
9	TOTAL ANNUALIZED PAYROLL (Line 1 + Line 8)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
	LESS:				
10	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	
11	INDIRECT TIME (Line 9 X Line 10)	$ 8,763,049	$ 360,238	$ 4,515,773	
12	NET ANNUALIZED LABOR (Line 9 + Line 11)	$ 55,981,703	$ 2,561,817	$ 32,113,712	
13	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	
14	O & M SUBTOTAL (Line 12 X Line 13)	$ 45,354,815	$ 2,561,817	$ 30,993,739	
15	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	
16	O & M SUBTOTAL ALLOCABLE (Line 14 X Line 15)	$ 45,354,815	$ 2,561,817	$ 17,846,195	
17	NET OF PAIUTE (SEE NOTE A)	$ -	$ -	$ (704,228)	
18	O & M TOTAL ALLOCABLE (Line 16 + Line 17)	$ 45,354,815	$ 2,561,817	$ 17,141,967	
19	COMPANY AS FILED (WP C-2, ADJ. 3, SH 15 & 20)	$ 48,546,243	$ 2,620,441	$ 17,552,008	
20	RUCO ADJUSTMENT (Line 18 - Line 19)	$ (3,191,429)	$ (58,624)	$ (410,041)	$ (3,660,095)
21	ANNUALIZED EMPLOYEES (WP C-2, ADJ. 3, SH 3)	1,171	39	502	1,712

NOTE (A)

LINE NO.	DESCRIPTION	AMOUNT
22	PAIUTE ADJUSTMENT	
23	RUCO ADJUSTED 920	$ 29,532,138
24	RUCO ADJUSTED 930	29,401
25	RUCO ADJUSTED 935	181,977
26	SUBTOTAL (Sum Of Lines 23, 24 & 25)	$ 29,743,515
27	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)	-4.29%
28	NET SYSTEM ALLOCATON - PAIUTE (Line 26 X Line 28)	$ (1,275,997)
29	O & M RATIO (WP C-2, ADJ. 3, SH 20)	95.85%
30	O & M SUBTOTAL (Line 28 X Line 29)	$ (1,223,043)
31	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 20)	57.58%
32	SYSTEM ALLOCATION - PAIUTE (Line 30 X Line 31)	$ (704,228)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED FICA, MEDICARE, FUTA, AND SUTA

LINE NO.	DESCRIPTION	(A) ARIZONA DIRECT	(B) CORPORATE DIRECT	(C) SYSTEM ALLOCABLE	(D) TOTAL
	ANNUALIZED FICA				
1	RUCO ANNUALIZED LABOR (RLM-8, PG. 3, LINE 9)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
2	SALARIES NOT SUBJECT TO FICA (RUCO DR 2.08)	693,076	233,025	2,989,398	
4	LABOR SUBJECT TO FICA (Line 1 - Line 2)	$ 64,051,676	$ 2,689,030	$ 33,640,086	
5	FICA RATE	6.20%	6.20%	6.20%	
6	TOTAL ANNUALIZED FICA (Line 4 X Line 5)	$ 3,971,204	$ 166,720	$ 2,085,685	
	ANNUALIZED MEDICARE				
7	ANNUALIZED LABOR (Line 1)	$ 64,744,752	$ 2,922,055	$ 36,629,484	
8	MEDICARE RATE	1.45%	1.45%	1.45%	
9	TOTAL ANNUALIZED MEDICARE (Line 7 X Line 8)	$ 938,799	$ 42,370	$ 531,128	
10	TOTAL FICA AND MEDICARE (Line 6 + Line 9)	$ 4,910,003	$ 209,090	$ 2,616,813	$ 7,735,905
	FUTA				
11	TAX BASE FACTOR	$ 7,000	$ 7,000	$ 7,000	
12	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
13	TAX BASE (Line 11 X Line 12)	$ 8,197,000	$ 273,000	$ 3,514,000	
14	FUTA RATE	0.80%	0.80%	0.80%	
15	TOTAL FUTA (Line 13 X Line 14)	$ 65,576	$ 2,184	$ 28,112	$ 95,872
	SUTA				
16	TAX BASE FACTOR	$ 7,000	$ 22,000	$ 22,000	
17	NUMBER OF EMPLOYEES (WP, ADJ. 3, SH 4)	1171	39	502	
18	TAX BASE (Line 16 X Line 17)	$ 8,197,000	$ 858,000	$ 11,044,000	
19	SUTA RATE	0.06%	0.30%	0.30%	
20	TOTAL SUTA (Line 18 X Line 19)	$ 4,918	$ 2,574	$ 33,132	$ 40,624
	NET OF PAIUTE (SEE NOTE A)			$ (606,425)	
21	TOTAL LABOR LOADING (Sum Of Lines 11, 16 & 21)	$ 4,980,497	$ 213,848	$ 2,071,632	$ 7,872,402
22	COMPANY AS FILED (WP C-2, ADJ. 3, SH 5)	$ 5,329,017	$ 218,963	$ 2,742,440	$ 8,290,420
23	DIFFERENCE (Line 21 - Line 22)	$ (348,520)	$ (5,115)	$ (670,808)	$ (1,024,443)
	LESS:				
24	PERCENT INDIRECT TIME (WP C-2, ADJ. 3, SH 4)	13.53%	12.33%	12.33%	12.74%
25	INDIRECT TIME (Line 23 X Line 24)	$ (47,171)	$ (631)	$ (82,699)	$ (130,501)
26	NET ANNUALIZED LABOR LOADING (L 23 - L 25)	$ (301,349)	$ (4,485)	$ (588,109)	$ (893,942)
27	O & M RATIO (WP C-2, ADJ. 3, SH 2)	81.02%	100.00%	96.51%	91.31%
28	O & M SUBTOTAL (Line 26 X Line 27)	$ (244,144)	$ (4,485)	$ (567,599)	$ (816,228)
29	ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 15)	100.00%	100.00%	57.58%	70.50%
30	RUCO ADJUSTMENT (Line 28 X Line 29)	$ (244,144)	$ (4,485)	$ (326,823)	$ (575,452)

NOTE (A)
PAIUTE ADJUSTMENT

LINE NO.	DESCRIPTION	AMOUNT
31	RUCO ADJUSTED 920	$ 14,034,893
32	RUCO ADJUSTED 930	13,956
33	RUCO ADJUSTED 935	86,925
34	SUBTOTAL (Sum Of Lines 23, 24 & 25)	$ 14,135,775
35	PAIUTE ALLOCATION FACTOR (WP C-2, ADJ. 3, SH 19)	-4.29%
36	NET SYSTEM ALLOCATON - PAIUTE (Line 34 X Line 35)	$ (606,425)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		ARIZONA DIRECT			CORPORATE DIRECT			SYSTEM ALLOCATED		
LINE NO.	ACOUNT CODE	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 3	RUCO AS ADJUSTED Col. (A) - (B)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 3	RUCO AS ADJUSTED Col. (D) - (E)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 3	RUCO AS ADJUSTED Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 466,263	$ (10,431)	$ 455,832	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	4,514,052	(296,754)	4,217,298	306,811	(6,864)	299,947	-	-	-
4	871	12,372	(813)	11,559	349,654	(7,822)	341,832	-	-	-
5	874	3,444,633	(226,450)	3,218,183	-	-	-	-	-	-
6	875	1,294,752	(85,117)	1,209,635	-	-	-	-	-	-
7	878	3,818,483	(251,027)	3,567,456	-	-	-	-	-	-
8	879	4,511,165	(296,564)	4,214,601	-	-	-	-	-	-
9	880	4,121,590	(270,953)	3,850,637	28,484	(637)	27,847	-	-	-
10	901	2,353,532	(154,721)	2,198,811	-	-	-	-	-	-
11	902	3,380,842	(222,256)	3,158,586	-	-	-	-	-	-
12	903	8,721,804	(573,371)	8,148,433	1,365,563	(30,550)	1,335,013	1,572,645	(20,338)	1,552,307
13	905	245,780	(16,158)	229,622	-	-	-	-	-	-
14	908	181,489	(11,931)	169,558	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	517	(34)	483	-	-	-	-	-	-
17	920	-	-	-	-	-	-	29,919,071	(386,933)	29,532,138
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	29,786	(385)	29,401
20	SUBTOTAL	$36,601,011	$ (2,406,150)	$34,194,861	$ 2,516,775	$ (56,305)	$ 2,460,470	$31,521,502	$ (407,657)	$31,113,845
	MAINTENANCE									
21	885	$ 1,460,701	$ (96,026)	$ 1,364,675	$ 103,666	$ (2,319)	$ 101,347	$ -	$ -	$ -
22	886	9,036	(594)	8,442	-	-	-	-	-	-
23	887	4,945,102	(325,091)	4,620,011	-	-	-	-	-	-
24	889	736,861	(48,441)	688,420	-	-	-	-	-	-
25	892	3,503,130	(230,296)	3,272,834	-	-	-	-	-	-
26	893	742,977	(48,843)	694,134	-	-	-	-	-	-
27	894	99,171	(6,519)	92,652	-	-	-	-	-	-
28	935	448,253	(29,468)	418,785	-	-	-	184,361	(2,384)	181,977
29	SUBTOTAL	$11,945,231	$ (785,279)	$11,159,952	$ 103,666	$ (2,319)	$ 101,347	$ 184,361	$ (2,384)	$ 181,977
30	TOTALS	$48,546,242	$ (3,191,429)	$45,354,813	$ 2,620,441	$ (58,624)	$ 2,561,817	$31,705,863	$ (410,041)	$31,295,822

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
ANUALIZED LABOR LOADING

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		ARIZONA DIRECT			CORPORATE DIRECT			SYSTEM ALLOCATED		
LINE NO.	ACOUNT CODE	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (A) - (B)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (D) - (E)	COMPANY AS FILED Co. WP, Adj. 3	RUCO ADJUSTMENT Pro Rated Pg 4	RUCO AS ADJUSTED Col. (G) - (H)
	OPERATIONS									
1	813	$ -	$ -	$ -	$ 216,923	$ (784)	$ 216,139	$ -	$ -	$ -
2	851	-	-	-	-	-	-	-	-	-
3	870	2,333,170	(22,673)	2,310,497	160,225	(579)	159,646	-	-	-
4	871	6,332	(62)	6,270	163,074	(590)	162,484	-	-	-
5	874	1,783,068	(17,327)	1,765,741	-	-	-	-	-	-
6	875	669,372	(6,505)	662,867	-	-	-	-	-	-
7	878	1,978,084	(19,222)	1,958,862	-	-	-	-	-	-
8	879	2,339,375	(22,733)	2,316,642	-	-	-	-	-	-
9	880	2,130,208	(20,701)	2,109,507	12,804	(46)	12,758	-	-	-
10	901	1,220,925	(11,865)	1,209,060	-	-	-	-	-	-
11	902	1,749,700	(17,003)	1,732,697	-	-	-	-	-	-
12	903	4,510,540	(43,832)	4,466,708	633,581	(2,291)	631,290	754,251	(16,217)	738,034
13	905	127,091	(1,235)	125,856	-	-	-	-	-	-
14	908	93,944	(913)	93,031	-	-	-	-	-	-
15	909	-	-	-	-	-	-	-	-	-
16	910	256	(2)	254	-	-	-	-	-	-
17	920	-	-	-	-	-	-	14,343,283	(308,390)	14,034,893
18	922	-	-	-	-	-	-	-	-	-
19	930	-	-	-	-	-	-	14,263	(307)	13,956
20	SUBTOTAL	$18,942,065	$ (184,074)	$18,757,991	$ 1,186,607	$ (4,290)	$ 1,182,317	$15,111,797	$ (324,913)	$14,786,884
	MAINTENANCE									
21	885	$ 755,990	$ (7,346)	$ 748,644	$ 53,906	$ (195)	$ 53,711	$ -	$ -	$ -
22	886	4,643	(45)	4,598	-	-	-	-	-	-
23	887	2,558,597	(24,864)	2,533,733	-	-	-	-	-	-
24	889	381,282	(3,705)	377,577	-	-	-	-	-	-
25	892	1,814,423	(17,632)	1,796,791	-	-	-	-	-	-
26	893	383,721	(3,729)	379,992	-	-	-	-	-	-
27	894	51,149	(497)	50,652	-	-	-	-	-	-
28	935	231,762	(2,252)	229,510	-	-	-	88,835	(1,910)	86,925
29	SUBTOTAL	$ 6,181,567	$ (60,071)	$ 6,121,496	$ 53,906	$ (195)	$ 53,711	$ 88,835	$ (1,910)	$ 86,925
30	TOTALS	$25,123,632	$ (244,144)	$24,879,488	$ 1,240,513	$ (4,485)	$ 1,236,028	$15,200,632	$ (326,823)	$14,873,809

EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 3 - CONT'D
REMOVING SALARIES OF SALES AND MARKETING EMPLOYEES

LINE NO.	ACCOUNT CODE	(A) DIRECT EMP'S SALARIES IN SALES/MRKT'G	(B) SYSTEM ALLOCABLE EMP'S SALARIES IN SALES/MRKT'G	(C) NO. OF EMPLOYEES
	INFORMATION FROM COMPANY RESPONSE TO RUCO DATA REQUEST NUMBER 2.08.b			
1		$ (76,567)		1
2		(75,965)		2
3		(71,972)		3
4		(69,784)		4
5		(85,440)		5
6		(76,898)		6
7		(76,026)		7
8		(67,153)		8
9		(71,879)		9
10		(83,776)		10
11		(93,764)		11
12		(100,608)		12
13			$ (84,367)	13
14			(99,256)	14
15			(89,679)	15
16			(78,026)	16
17			(85,794)	17
18			(72,339)	18
19			(91,792)	19
20			(91,424)	20
21			(87,373)	21
22			(99,226)	22
23		(58,385)		23
24		(62,896)		24
25		(70,924)		25
26		(72,660)		26
27		(76,949)		27
28		(67,338)		28
29		(67,842)		29
30		(73,103)		30
31		(67,348)		31
32		(70,584)		32
33		(82,998)		33
34		(86,966)		34
35		(93,299)		35
36		(103,221)		36
37		(120,921)		37
42	TOTALS	$ (2,125,266)	$ (879,276)	
43	ALLOCATION FACTOR	100.00%	87.25%	
44	ALLOCABLE TOTAL (See RLM-8, Page 3, Line 2)	$ (2,125,266)	$ (767,168)	$ (2,892,434)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 7
AMERICAN GAS ASSOCIATION (AGA) DUES

LINE NO	DESCRIPTION		(A) RUCO AS ADJUSTED
1	2004 AGA Dues (Company Schedule C-2, Adjustment No. 7)	$	384,566
	Less:		
2	Paiute And SGTC Allocation Factor (Company Schedule C-1, Sheet 19)		-4.29%
3	Paiute And SGTC Allocation (Line 1 X Line 2)		(16,498)
4	Adjustment To AGA Dues Before 4-Factor (Line 1 + Line 3)	$	368,068
5	System Allocation Factor (Company Schedule C-1, Sheet 18)		57.58%
6	Arizona AGA Dues (Line 4 X Line 5)	$	211,934
7	Adjustment To Remove Lobbying And Adverising Portion Of SWG's AGA Dues Percent Disallowed (See NOTE A)		39.09%
8	Subtotal (Line 6 x Line 7)	$	82,845
	Less:		
9	Amount Removed By SWG (Company Schedule C-2, Adjustment No. 7)		7,460
10	RUCO ADJUSTMENT TO SWG's AGA DUES (Line 8 - Line 9) (See RLM-7, Page 1, Column (E))	$	75,385

NOTE A

As Per Company Response To RUCO Data Request No. 14.2
Categories Of Disallowance:

			Percentage
11		Public Affairs	23.35%
12		Communications	15.74%
13	Total		39.09%

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 10
INJURIES AND DAMAGES - SELF INSURED RETENTION NORMALIZATION

LINE NO	DESCRIPTION	REFERENCE	(A) 14 YEAR TOTAL	(B) TOTAL AZ ACCRUAL
1	Claims Paid			
2	< $1,000,000	Response To RUCO DR 14	$ 8,557,891	
3	At $1,000,000	Response To RUCO DR 14	10,000,000	
4	> $1,000,000 < $10,000,000	Response To RUCO DR 14 (less claims over $10 M)	27,547,300	
5	Total Claims Paid	(Sum Of Lines 2, 3 & 4)	$ 46,105,191	
6	14 Year Average	Line 5 / 14 Years		$ 3,293,228
	Less:			
7	FERC Allocation Factor	Co. Sch. C-1, Sh 18		4.29%
8	FERC Allocation	Line 6 X Line 7		(141,279)
9	Net System Allocable	Sum Of Lines 6 & 8		$ 3,151,948
10	Arizona 4-Factor	Co. Sch. C-1, Sh 19		57.58%
11	Net Arizona Allocated	Line 9 X Line 10		$ 1,814,892
12	Company Injuries And Damages Expenses As Filed	Sch. C-2, Adj. No. 10, Column (f), Line 8		$ 2,161,296
13	Difference	Line 11 - Line 12		$ (346,404)
14	RUCO ADJUSTMENT TO INJURIES AND DAMAGES EXPENSE (See RLM-7, Page 1, Column (G))			$ (346,404)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 14
MISCELLANEOUS ADJUSTMENTS

		(A)	(B)	(C)	(D)
		RUCO ADJUSTMENTS			
LINE NO	DESCRIPTION	ALLOCABLE TOTAL	ALLOC'N FACTOR	ARIZONA TOTAL	RUCO AS ADJUSTED
	Arizona Direct Accounts				
1	870 - Operation Supervision And Engineering	$ (25,337)	100.00%	$ (25,337)	
2	875 - Measuring And Regulating Expenses - General	N/A	100.00%	-	
3	880 - Other Expenses	(162,828)	100.00%	(162,828)	
4	Sub Total Distribution	$ (188,165)			$ (188,165)
5	902 - Meter Reading	$ (10,715)	100.00%	$ (10,715)	
6	903 - Customer Records And Collection Expenses	N/A	100.00%	-	
7	Sub Total Customer Accounts	$ (10,715)			$ (10,715)
8	908 - Customer Assistance Expenses	N/A	100.00%	$ -	
9	910 - Miscellaneous Customer Service And Information Expenses	N/A	100.00%	-	
10	Sub Total Customer Service And Information Expenses	$ -			$ -
11	Sub Total Arizona Direct Accounts	$ (198,880)			$ (198,880)
	System Allocable Accounts To Arizona				
12	903 - Customer Records And Collection Expenses	N/A	55.40%	$ -	
13	Sub Total Customer Accounts	$ -			$ -
14	921 - Office Supplies And Expenses	$ (170,593)	57.58%	$ (98,227)	
16	923 - Outside Services Employed	(27,768)	57.58%	(15,989)	
17	930 - Miscellaneous General Expenses	(57,664)	57.58%	(33,203)	
18	Sub Total Administrative And General Expenses	$ (256,025)			$ (147,419)
19	Sub Total System Allocable Accounts To Arizona	$ (256,025)			$ (147,419)
20	RUCO ADJUSTMENT TO MISCELLANEOUS ADJUSTMENTS (See RLM-7, Page 1, Column (I))				$ (346,299)

References:
Column (A): See Testimony, RLM
And Workpapers RLM-11WP(870) Pages 1 To 4, RLM-11WP(880) Pages 1 To 18, RLM-11WP(902) Pages 1 To 3, RLM-11WP(921) Pages 1 To 13, RLM11-WP(923) Page 1, RLM-11WP(930) Page 1
Column (B): Company Schedule C-2, Adjustment No. 14
Column (C): Column (A) X Column (B)
Column (D): Sums Of Column (C)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 17
DIRECT PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301	Organization	$ 42,653	Amortized	$ -
2	302	Franchises & Consents	1,714,402	Amortized	77,626
3	303	Miscellaneous Intangible	1,945,631	Amortized	132,362
4		Total Intangible Plant	$ 3,702,686		$ 209,988
		Distribution Plant:			
5	374.1	Land & Land Rights	$ 351,685	0.00%	$ -
6	374.2	Rights Of Way	720,979	2.15%	15,501
7	375	Structures	110,557	1.15%	1,271
8	376	Mains	786,937,551	3.82%	30,061,014
9	378	Measuring & Regulating Station	24,454,990	4.12%	1,007,546
10	380	Services	522,687,054	5.30%	27,702,414
11	381	Meters	156,809,964	1.98%	3,104,837
12	385	Industrial Measuring & Regulating Station	6,528,499	4.31%	281,378
13	387	Other Equipment	462,730	5.26%	24,340
14		Total Distribution Plant	$ 1,499,064,009		$ 62,198,302
		General Plant:			
15	389	Land & Land Rights	$ 6,454,589	0.00%	$ -
16	390.1	Structures	26,285,123	1.84%	483,646
17	390.2	Structures - Leasehold Improvments	1,005,567	Amortized	62,345
18	391	Office Furniture And Equipment	4,849,827	2.73%	132,400
19	391.1	Computer Equipment	8,489,038	14.87%	1,262,320
20	392.1	Transportation Equipment	30,447,147	7.65%	2,329,207
21	393	Stores Equipment	481,909	2.08%	10,024
22	394	Tools, Shop And Garage Equipment	4,891,998	2.17%	106,156
23	395	Laboratory Equipment	425,322	3.93%	16,715
24	396	Power Operated Equipment	3,807,547	3.88%	147,733
25	397	Communication Equipment	2,223,684	8.88%	197,463
26	397.2	Telemetering Equipment	560,307	6.19%	34,683
27	398	Miscellaneous Equipment	844,186	4.53%	38,242
28		Total General Plant	$ 90,766,244		$ 4,820,934
29		TOTAL DIRECT PLANT	$ 1,593,532,939		$ 67,229,224
30		Company Direct Plant As Filed	1,597,358,113		67,338,861
31		Difference	(3,825,174)		$ (109,637)
32		RUCO ADJUSTMENT TO TEST YEAR DIRECT DEPRECIATION EXPENSE (See RLM-7, Page 2, Column (J))			$ (109,637)

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 17 - CONT'D
SYSTEM ALLOCABLE PLANT TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.		(A) TOTAL PLANT VALUE	(B) CO. PROPOSED DEPRECIATION RATE	(C) TEST YEAR DEPREC'N EXPENSE
		Intangible Plant:			
1	301.0	Organization	$ 61,816	0.00%	$ -
2	302.0	Franchises & Consents	-	Amortized	-
3	303.0	Miscellaneous Intangible	105,328,240	Amortized	# 7,977,861
4		Total Intangible Plant	$ 105,390,056		$ 7,977,861
		Distribution Plant:			
5	374.1	Land & Land Rights	$ -	0.00%	$ -
6	374.2	Rights Of Way	-	0.00%	-
7	375.0	Structures	-	0.00%	-
8	376.0	Mains	-	0.00%	-
9	378.0	Measuring & Regulating Station	-	0.00%	-
10	380.0	Services	-	0.00%	-
11	381.0	Meters	-	0.00%	-
12	385.0	Industrial Measuring & Regulating Station	-	0.00%	-
13	387.0	Other Equipment	-	0.00%	-
14		*Total Distribution Plant*	$ -		$ -
		General Plant:			
15	389.0	Land & Land Rights	$ 391,307	0.00%	$ -
16	390.1	Structures	11,831,108	2.50%	295,778
17	390.2	Structures - Leasehold Improvments	3,144,329	Amortized	29,729
18	391.0	Office Furniture And Equipment	7,751,650	8.16%	632,535
19	391.1	Computer Equipment	13,445,898	16.15%	2,171,513
20	392.1	Transportation Equipment	3,338,897	7.20%	240,401
21	393.0	Stores Equipment	111,293	7.20%	8,013
22	394.0	Tools, Shop And Garage Equipment	7,386	16.03%	1,184
23	395.0	Laboratory Equipment	414,693	11.16%	46,280
24	396.0	Power Operated Equipment	268,894	4.77%	12,826
25	397.0	Communication Equipment	4,605,689	8.51%	391,944
26	397.2	Telemetering Equipment	401,430	40.23%	161,495
27	398.0	Miscellaneous Equipment	934,686	11.09%	103,657
28		Total General Plant	$ 46,647,260		$ 4,095,354
29		TOTAL ALLOCABLE PLANT	$ 152,037,316		$ 12,073,215
31		Company As Filed	$ 153,085,151		$ 12,265,743
32		Difference	$ (1,047,835)		$ (192,528)
30		Allocation Factor	57.58%		57.58%
31		ALLOCATED PLANT	$ (603,341)		$ (110,857)

32 RUCO ADJUSTMENT TO TEST YEAR SYSTEM ALLOCATED DEPRECIATION (See RLM-7, Page 2, Column (J)) $ (110,857)

NOTE: AMOUNT IN COLUMN (C), LINE 3 INCLUDES THE ADJUSTMENT FROM SCHEDULE MDC-6

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EXPLANATION OF SWG OPERATING INCOME ADJUSTMENT NO. 18
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	(A)	(B)
	Calculation Of The Company's Full Cash Value:		
1	Net Plant In Service		$ 1,047,658,883
	ADD:		
2	Materials And Supplies (Company Schedule B-5, Sheet 1, Column (c), Line 2)	9,222,489	
3	Total (Line 2)		$ 9,222,489
	SUBTRACT:		
4	Original Cost Of Trans Equip (RLM-3, Pg 1, Col (M), L 20 + Pg 2, Col (M), L 20 + L 21)	$ 33,897,337	
5	Acc. Dep. Of Trans Equip (RLM-3, Pg 1, Col (N), L 20 + Pg 2, Col (N), L 20 + L 21)	$ 6,354,715	
6	Book Value Of Transportation Equipment (Line 5 - Line 6 Expressed In The Negative)		$ (27,542,622)
7	Land Rights (Company Sch. C-2, Adj. 18)		$ (797,670)
8	COMPANY'S FULL CASH VALUE (Sum Of Lines 1, 3, 6 & 7)		$ 1,028,541,080
	Calculation Of The Company's Tax Liability:		
	MULTIPLY: Company Full Cash Value By Valuation Assessment Ratio And Then By Property Tax Rates:		
9	Assessment Ratio (Per House Bill 2779)	24.5%	
10	Assessed Value (Line 8 X Line 9)	$ 251,992,565	
	Property Tax Rates:		
11	Primary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	12.77%	
12	Secondary Tax Rate (2004 Tax Notice - Co.'s Data Response - "Property Tax")	0.00%	
13	Estimated Tax Rate Liability (Line 11 + Line 12)	12.77%	
14	COMPANY'S TAX LIABILITY - Based On Full Cash Value (Line 10 X Line 13)		$ 32,179,450
15	Test Year Adjusted Property Tax Expense Per Company's Filing (Co. Sch. C-2, Adj No. 18))	$ 33,447,313	
16	Increase (Decrease) In Property Tax Expense (Line 14 - Line 15)	$ (1,267,863)	
17	RUCO ADJUSTMENT TO PROPERTY TAX EXPENSE (See RLM-7, Page 2, Column (K))		$ (1,267,863)

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EXPLANATION OF RUCO OPERATING INCOME ADJUSTMENT NO. 21
SUPPLEMENTAL EMPLOYEE RETIREMENT PLAN

LINE NO	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO AS ADJUSTED	(C) DISTRIBUTION PERCENTAGE	(D) RUCO ADJUSTMENT
	ALLOCATIONS:	WP C-2, Adj #3, Sh 8, L 11	Col (A) + Col (D)	WP C-2, Adj #3, Sh 8, L 13	Distributed Total RUCO DR 14-1.a
1	Arizona	$ 2,109,491	$ 979,554	41.93%	$ (1,129,937)
2	Corporate Direct	97,085	45,082	1.93%	(52,003)
3	Other Jurisdictions	1,578,657	733,058	31.38%	(845,599)
4	System Allocable	1,245,471	578,342	24.76%	(667,129)
5	Total (Sum Of Lines 1, 2, 3 & 4)	$ 5,030,704	$ 2,336,036	100.00%	$ (2,694,668)

FUNCTIONALIZATION:

LINE NO	DESCRIPTION	DISTRIBUTION PRECENTAGE See NOTE A	DISTRIBUTION Of Col (D), Line 1	ALLOCATION FACTOR	RUCO ADJUSTMENT RLM-7, Pg 2, Col (M)
6	OTHER GAS SUPPLY (813)	0.87%	$ (9,815)	100.00%	$ (9,815)
7	DISTRIBUTION (870-880 & 885-894)	65.12%	(735,813)	100.00%	(735,813)
8	CUST. ACC'TS (901, 902, 903 & 905)	33.66%	(380,369)	100.00%	(380,369)
9	CUST. SER. & INFO (908, 909, & 910)	0.35%	(3,939)	100.00%	(3,939)
10	SUBTOTAL Sum Of Lines 6 Thru 9)	100.00%	(1,129,937)		
11	SALES				-
	ADMINISTRATION & GENERAL		DISTRIBUTION Of Col (D), L 2 & L4		
12	CORPORATE DIRECT (935)		(52,003)	100.00%	(52,003)
13	SYS. ALLOC. (920, 922, 930 & 935)		(667,129)	57.58%	(384,133)
14	TOTAL (Sum Of Lines 10, 12 & 13) (See RLM-7, Pg 2, Col (M))		$ (1,849,069)		$ (1,566,073)

NOTE A

To Determine The Distribution Ratio Of Arizona Direct SERP
By Allocating Expenses At The Same Percentage As Labor Loading In Adjustment No. 3

LINE NO	DESCRIPTION	ADJ'MENT NO.3 RLM-8, PG 1	DISTRIBUTION PRECENTAGE
15	OTHER GAS SUPPLY (813)	$ 671,971	0.87%
16	DISTRIBUTION (870-880 & 885-894)	50,376,691	65.12%
17	CUST. ACC'TS (901, 902, 903 & 905)	26,041,593	33.66%
18	CUST. SER. & INFO (908, 909, & 910)	269,705	0.35%
19	SUBTOTAL	77,359,960	100.00%

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EXPLANATION OF OPERATING INCOME ADJUSTMENT
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Schedule RLM-6, Column (C), Line 18 + Line 16	$ 59,317,635
	LESS:		
2	Arizona State Tax	Line 11	(1,592,748)
3	Interest Expense	Note (A) Line 21	(36,459,599)
4	Federal Taxable Income	Sum Of Lines 1, 2 & 3	$ 21,265,289
5	Federal Tax Rate	Schedule RLM-1, Page 2, Column (A), Line 10	35.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 7,442,851
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 59,317,635
	LESS:		
8	Interest Expense	Note (A) Line 21	(36,459,599)
9	State Taxable Income	Line 7 + Line 8	$ 22,858,037
10	State Tax Rate	Tax Rate	6.9680%
11	State Income Tax Expense	Line 9 X Line 10	$ 1,592,748
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 7,442,851
13	State Income Tax Expense	Line 11	1,592,748
14	South Georgia Amortization	Company Schedule C-1, Sheet 17, Column (C), Line 8 + Line 18	365,253
15	Investment Tax Credit	Company Schedule C-1, Sheet 17, Column (C), Line 19	(528,352)
16	Total Income Tax Expense Per RUCO	Sum Of Lines 12, 13, 14 & 15	$ 8,872,500
17	Total Income Tax Expense Per Company Filing (Schedule C-1)		2,156,664
18	RUCO ADJUSTMENT TO INCOME TAX EXPENSE (See RLM 7, Page 2, Column (Q))	Line 16 - Line 17	$ 6,715,836

NOTE (A):
Interest Synchronization:

19	Adjusted Rate Base (Schedule RLM-2, Column (C), Line 10)	$ 918,447,207
20	Weighted Cost Of Debt (Schedule RLM-18, Column (F), Line 1 + Line 2)	3.97%
21	Interest Expense (Line 19 X Line 20)	$ 36,459,599

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PROPOSED MARGIN RATES BASIC SERVICE CHARGE	(F) PROPOSED MARGIN RATES COMMODITY CHARGE	(G) BASIC SERVICE CHARGE	(H) MARGIN AT PROPOSED RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	Single-Family Residential Gas Service	G-5							
1	Basic Service Charge per Month		9,563,921		$ 9.36		$ 89,520,069		$ 89,520,069
2	Commodity Charge All Therms			265,765,100		0.487185		129,476,751	129,476,751
3	Total Single-Family Residential Gas Service		9,563,921	265,765,100			$ 89,520,069	$ 129,476,751	$ 218,996,820
	Low Income Residential Gas Service	G-5							
4	Basic Service Charge per Month		345,978		9.36		$ 3,238,420		$ 3,238,420
5	Commodity Charge All Therms			9,553,429		0.487185		4,654,287	4,654,287
						0.487185		-	-
6	Total Low Income Residential Gas Service		345,978	9,553,429			$ 3,238,420	$ 4,654,287	$ 7,892,707
	Multi-Family Residential Gas Service	G-6							
7	Basic Service Charge per Month		748,946		8.19		$ 6,133,989		$ 6,133,989
8	Commodity Charge All Therms			14,987,992		0.487185		7,301,924	7,301,924
						0.487185		-	-
9	Total Multi-Family Residential Gas Service		748,946	14,987,992			$ 6,133,989	$ 7,301,924	$ 13,435,912
	Multi-Family Low Income Residential Gas Service	G-6							
10	Basic Service Charge per Month		55,465		8.19		$ 454,269	$ -	$ 454,269.09
11	Commodity Charge All Therms			1,213,156		0.487185		591,031.30	591,031.30
						0.487185		-	-
12	Total Multi-Family Low-Income Gas Service		55,465	1,213,156			$ 454,269	$ 591,031	$ 1,045,300
13	Total Residential Gas Service		10,714,311	291,519,677			99,346,747	142,023,993	241,370,740
	Master Metered Mobile Home Park Gas Service	G-20							
30	Basic Service Charge per Month		2,462		$ 127.35		$ 313,589		$ 313,589
31	Commodity Charge per Therm			2,505,221		0.283626		710,545	710,545
32	Total Master Metered Mobile Home Park Gas Service		2,462	2,505,221			313,589	710,545	1,024,134
	General Gas Service - Small	G-25(S)							
	Basic Service Charge per Month								
1	Former Small Gas Service Customers		214,764		$ 31.84		$ 6,837,667		$ 6,837,667
2	Former Medium Gas Service Customers		104		$ 31.84		3,318		3,318
3	Former Essential Agriculture Customers		156		$ 31.84		4,978		4,978
	Commodity Charge per Therm								
4	Transportation Customers			643		0.607100		390	390
5	Sales Customers			3,867,813		0.607100		2,348,150	2,348,150
6	Total Small General Gas Service		215,024	3,868,456			$ 6,845,963	$ 2,348,540	$ 9,194,503

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

LINE NO.	(A) DESCRIPTION	(B) PROPOSED SCHEDULE NO.	(C) BILLING DETERMINANTS NUMBER OF BILLS	(D) BILLING DETERMINANTS SALES (THERMS)	(E) PRESENT MARGIN RATES BASIC SERVICE CHARGE	(F) PRESENT MARGIN RATES COMMODITY CHARGE	(G) MARGIN AT PRESENT RATES BASIC SERVICE CHARGE	(H) MARGIN AT PRESENT RATES COMMODITY CHARGE	(I) TOTAL MARGIN
	General Gas Service - Medium	G-25(M)							
	Basic Service Charge per Month								
7	Former Small Gas Service Customers		207,728		$ 44.57		$ 9,259,145		$ 9,259,145
8	Former Medium Gas Service Customers		4,026		44.57		179,442		179,442
9	Former Large Gas Service Customers		13		44.57		581		581
10	Former Armed Forces Customers		26		44.57		1,161		1,161
11	Former Essential Agriculture Customers		560		44.57		24,971		24,971
	Commodity Charge per Therm								
	Transportation Customers								
12	Former Small Gas Service Customers			103,604		0.352337		36,504	36,504
13	Former Medium Gas Service Customers			87,082		0.352337		30,682	30,682
	Sales Customers			-					
14	Former Small Gas Service Customers			41,835,599		0.352337		14,740,233	14,740,233
15	Former Medium Gas Service Customers			1,782,746		0.352337		628,127	628,127
16	Former Large Gas Service Customers			5,159		0.352337		1,818	1,818
17	Former Armed Forces Customers			3,930		0.352337		1,385	1,385
18	Former Essential Agriculture Customers			136,422		0.352337		48,067	48,067
19	Total Medium General Gas Service		212,353	43,954,541			$ 9,465,300	$ 15,486,814	$ 24,952,114
	General Gas Service - Large	G-25(L)							
	Basic Service Charge per Month								
20	Former Small Gas Service Customers		4,750		$ 191.03		$ 907,375		$ 907,375
21	Former Medium Gas Service Customers		86,187		191.03		16,464,241		16,464,241
22	Former Large Gas Service Customers		130		191.03		24,888		24,888
23	Former Armed Forces Customers		26		191.03		4,978		4,978
	Commodity Charge per Therm								
	Transportation Customers								
24	Former Small Gas Service Customers			83,642		0.240806		20,141	20,141
25	Former Medium Gas Service Customers			2,754,626		0.240806		663,331	663,331
26	Former Large Gas Service Customers			323,190		0.240806		77,826	77,826
	Sales Customers			-					
27	Former Small Gas Service Customers			3,002,106		0.240806		722,926	722,926
28	Former Medium Gas Service Customers			137,636,528		0.240806		33,143,743	33,143,743
29	Former Large Gas Service Customers			1,078,065		0.240806		259,605	259,605
30	Former Armed Forces Customers			172,404		0.240806		41,516	41,516
31	Total Large General Gas Service		91,094	145,050,561			$ 17,401,482	$ 34,929,090	$ 52,330,572
	General Gas Service - Transportation Eligible	G-25(TE)							
	Basic Service Charge per Month								
32	Former Medium Gas Service Customers		65		$ 955.14		$ 62,220		$ 62,220
33	Former Essential Agriculture Customers		274		955.14		261,324		261,324
34	Former Large Gas Service Customers		1,824		955.14		1,742,160		1,742,160
35	Former Armed Forces Customers		65		955.14		62,220		62,220
36	Demand Charge Per Month			10,571,934		0.055057		6,984,770	6,984,770
	Commodity Charge per Therm								
	Transportation Customers								
37	Former Medium Gas Service Customers					0.081403		-	-
38	Former Essential Agriculture Customers			4,529,656		0.081403		368,725	368,725
39	Former Large Gas Service Customers			26,387,348		0.081403		2,147,997	2,147,997
	Sales Customers			-					
40	Former Medium Gas Service Customers			1,037,977		0.081403		84,494	84,494
41	Former Essential Agriculture Customers			5,172,762		0.081403		421,076	421,076
42	Former Large Gas Service Customers			47,458,640		0.081403		3,863,253	3,863,253
43	Former Armed Forces Customers			3,059,260		0.081403		249,031	249,031
44	Total Transportation Eligible General Gas Service		2,228	87,645,643			$ 2,127,924	$ 14,119,347	$ 16,247,271
45	Total General Gas Service		520,699	280,519,200	-	-	$ 35,840,669	$ 66,883,790	$ 102,724,459

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		PROPOSED	BILLING DETERMINANTS		PRESENT MARGIN RATES		MARGIN AT PRESENT RATES		
LINE NO.	DESCRIPTION	SCHEDULE NO.	NUMBER OF BILLS	SALES (THERMS)	BASIC SERVICE CHARGE	COMMODITY CHARGE	BASIC SERVICE CHARGE	COMMODITY CHARGE	TOTAL MARGIN
	Air Conditioning Gas Service	G-40							
	Basic Service Charge								
1	With Other Service (No Basic Service Charge)		65		$ -		$ -		$ -
2	Basic Service Charge		422		31.84		13,446		13,446
	Commodity Charge per Therm								
3	Transportation Customers			642,426		0.089717		57,636	57,636
4	Sales Customers			1,233,591		0.089717		110,674	110,674
5	Total Air Conditioning Gas Service		487	1,876,017			$ 13,446	$ 168,310	$ 181,757
	Street Lighting Gas Service	G-45							
	Commodity Charge per Therm Of Rated Capacity								
6	All Usage		378	102,030	$ -	$ 0.510274	$ -	$ 52,063	$ 52,063
7	Total Street Lighting Gas Service		378	102,030			$ -	$ 52,063	$ 52,063
	Gas Service For Compression On Customer's Premises	G-55							
	Basic Service Charge								
8	Small		287		$ 31.84	$ -	$ 9,126	$ -	$ 9,126
9	Large		352		445.73		156,794		156,794
10	Residential		1,433		9.36		13,414		13,414
	Commodity Charge per Therm								
11	Transportation Customers			-		0.1[illegible]99		-	-
	Sales Customers			-					
12	Small			186,231		0.11799		21,974	21,974
13	Large			1,939,619		0.11799		228,857	228,857
14	Residential			81,432		0.11799		9,608	9,608
15	Total Gas Service For Compression On Customer's Premises		2,072	2,207,283			$ 179,334	$ 260,439	$ 439,773
	Electric Generation Gas Service	G-60							
	Basic Service Charge								
16	General Service - Small		65		$ 31.84		$ 2,074		$ 2,074
17	General Service - Medium		-		44.57		-		-
18	General Service - Large		104		191.03		19,910		19,910
19	General Service - Transportation Eligible		104		955.14		99,552		99,552
20	Essential Agriculture		26		191.03		4,978		4,978
	Commodity Charge per Therm								
21	Transportation Customers			-		0.08954		-	-
22	Sales Customers			15,330,306		0.08954		1,372,691	1,372,691
23	Total Electric Generation Gas Service		300	15,330,306			$ 126,514	$ 1,372,691	$ 1,499,205
	Small Essential Agriculture User Gas Service	G-75							
24	Basic Service Charge		472		$ 191.03		$ 90,219	$ -	$ 90,219
	Commodity Charge per Therm								
25	Transportation Customers			159,244		0.19499		31,051	31,051
26	Sales Customers			2,849,131		0.19499		555,552	555,552
27	Total Small Essential Agriculture Gas Service		472	3,008,375			$ 90,219	$ 586,602	$ 676,821
	Natural Gas Engine Gas Service	G-80							
	Basic Service Charge								
28	Off-Peak Season (October - March)		3,933		$ -	$ -	$ -	$ -	$ -
29	On-Peak Season (April - September)		3,933		127.35		500,821		500,821
	Commodity Charge per Therm								
30	Transportation Customers			-		0.13929		-	-
31	Sales Customers			21,728,560		0.13929		3,026,485	3,026,485
32	Total Natural Gas Engine Gas Service		7,866	21,728,560			$ 500,821	$ 3,026,485	$ 3,527,306
33	Total Tariff Sales		11,249,047	618,796,668			136,411,339	215,084,918	351,496,257
34	Optional Gas Service	G-30	352	103,831,824	$ 1,576.36	0.04951	$ 554,511	$ 5,140,758	$ 5,695,269
35	Special Contract Service	B-1	294	31,064,410	$ 681.56	0.06413	$ 200,532	$ 1,992,049	$ 2,192,581
36	Other Operating Revenues						$ 11,434,480		$ 11,434,480
37	Total Revenue		11,249,693	753,692,902			$ 148,600,862	$ 222,217,725	$ 370,818,588
38	Recommended Annual Revenue Requirement								$ 370,818,589
39	Difference								$ (1)

Southwest Gas Corporation
Docket No. G-01551A-04-0876
Test Year Ended August 31, 2004

TYPICAL BILL ANALYSIS
SINGLE-FAMILY RESIDENTAL GAS SERVICE

COMPARISON OF PRESENT & PROPOSED RATE STRUCTURE

LINE NO.	DESCRIPTION	CONSP'TION (THERMS)	PRESENT SCHEDULES	PROPOSED SCHEDULES	DOLLAR INCREASE	PERCENT INCREASE
			SUMMER			
			May-October Break - 20 Therms	May-October Break - 8 Therms		
	Company					
1	25% Average Usage	3	$ 11.19	$ 19.74	$ 8.55	76.43%
2	75% Average Usage	9	$ 17.57	$ 26.52	$ 8.95	50.97%
3	Average Usage	12	$ 20.76	$ 28.66	$ 7.90	38.06%
4	150% Average Usage	19	$ 27.14	$ 32.93	$ 5.79	21.35%
5	200% Average Usage	25	$ 33.10	$ 37.20	$ 4.10	12.40%
	RUCO					
6	25% Average Usage	3	$ 11.07	$ 12.43	$ 1.36	12.27%
7	75% Average Usage	9	$ 17.22	$ 18.58	$ 1.36	7.88%
8	Average Usage	12	$ 20.29	$ 21.65	$ 1.35	6.68%
9	150% Average Usage	18	$ 26.44	$ 27.79	$ 1.35	5.11%
10	200% Average Usage	24	$ 32.59	$ 33.93	$ 1.35	4.14%
			SWING MONTHS			
			April & November Break - 40 Therms	April & November Break - 8 Therms		
	Company					
11	25% Average Usage	11	$ 19.59	$ 19.74	$ 0.16	0.79%
12	75% Average Usage	34	$ 42.76	$ 26.52	$ (16.23)	-37.97%
13	Average Usage	45	$ 53.90	$ 28.66	$ (25.23)	-46.82%
14	150% Average Usage	68	$ 75.16	$ 32.93	$ (42.23)	-56.18%
15	200% Average Usage	91	$ 96.42	$ 37.20	$ (59.22)	-61.42%
	RUCO					
16	25% Average Usage	11	$ 19.46	$ 20.81	$ 1.36	6.97%
17	75% Average Usage	34	$ 42.37	$ 43.71	$ 1.35	3.18%
18	Average Usage	45	$ 53.41	$ 55.16	$ 1.75	3.27%
19	150% Average Usage	67	$ 74.44	$ 78.06	$ 3.63	4.87%
20	200% Average Usage	90	$ 95.46	$ 100.96	$ 5.50	5.76%
			WINTER			
			December-March Break - 40 Therms	December-March Break - 30 Therms		
	Company					
21	25% Average Usage	11	$ 19.59	$ 29.59	$ 10.01	51.09%
22	75% Average Usage	34	$ 42.76	$ 54.71	$ 11.95	27.95%
23	Average Usage	45	$ 53.90	$ 62.47	$ 8.58	15.91%
24	150% Average Usage	68	$ 75.16	$ 77.99	$ 2.83	3.76%
25	200% Average Usage	91	$ 96.42	$ 93.51	$ (2.92)	-3.03%
	RUCO					
26	25% Average Usage	11	$ 19.46	$ 20.81	$ 1.36	6.97%
27	75% Average Usage	34	$ 42.37	$ 43.71	$ 1.35	3.18%
28	Average Usage	45	$ 53.41	$ 55.16	$ 1.75	3.27%
29	150% Average Usage	67	$ 74.44	$ 78.06	$ 3.63	4.87%
30	200% Average Usage	90	$ 95.46	$ 100.96	$ 5.50	5.76%
	PROPOSED AVERAGE RESIDENTIAL TOTAL ANNUAL GAS SERVICE COSTS					
31	**Company**		$ 447.93	$ 479.17	$ 31.24	6.97%
32	**RUCO**		$ 442.24	$ 460.85	$ 18.62	4.21%
	PRO-RATED AVERAGE RESIDENTIAL MONTHLY GAS SERVICE COSTS (ANNUAL COSTS DIVIDED BY 12 MONTHS)					
33	**Company**		$ 37.33	$ 39.93	$ 2.60	6.97%
34	**RUCO**		$ 36.85	$ 38.40	$ 1.55	4.21%

RATE SCHEDULES

PRESENT BASIC SERVICE

$ 8.00

PRESENT COMMODITY RATE

1.02198 *
0.9378 *

BREAKPOINTS

SUMMER (THERMS) (May - Oct)
20

WINTER (THERMS) (May - Oct)
40

PROPOSED RATE DESIGNS

	COMPANY	**RUCO**
BASIC SERVICE	$ 16.00	$ 9.36
COMMODITY RATE	1.1989 * 0.68436 *	1.02154 *
BREAKPOINTS		
SUMMER (THERMS) (Apr - Nov)	8	N/A
WINTER (THERMS) (Dec - Mar)	30	N/A

* - The Commodity Rate Includes Gas Costs Of $0.05346 Per Therm

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) PERCENT	(E) COST RATE	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 785,950,234	$ -	$ 785,950,234	53.00%	7.49%	3.97%
3	Preferred Stock	$ 100,000,000	$ -	$ 100,000,000	5.00%	8.20%	0.41%
4	Common Equity	$ 662,978,685	$ -	$ 662,978,685	42.00%	10.15%	4.26%
5	TOTAL CAPITAL	$ 1,548,928,919	$ -	$ 1,548,928,919	100.00%		
6	COST OF CAPITAL						8.64%

References:
- Column (A): Company Schedule D-1
- Column (B): Testimony, WAR
- Column (C): Column (A) + Column (B)
- Column (D): Column (C), Line Item / Total Capital (L5)
- Column (E): Testimony, WAR
- Column (F): Column (D) X Column (E)

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 26, 2005

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My Name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and your qualifications in the field of utilities regulation.

A. Appendix I, which is attached to this testimony, describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Southwest Gas Corporation's ("SWG" or "Company") application ("Application") for a permanent rate increase, which was filed with the Arizona Corporation Commission ("ACC" or "Commission") on December 9, 2004. The Company is based in Las Vegas, NV, and is publicly traded on the New York Stock Exchange ("NYSE"). SWG is the dominant local distribution company ("LDC") in Arizona and also provides natural gas distribution services in the states of California and Nevada. The Company has chosen the twelve-month period ended August 31, 2004 as the test year ("Test Year") for this proceeding.

Q. Please explain your role in RUCO's analysis of SWG's Application.

A. I reviewed SWG's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended costs of common equity, preferred equity and long-term debt. The recommendations contained in this testimony are based on information obtained from the Company's Application and on market-based research that I conducted during my cost of capital analysis.

Q. Were you also responsible for conducting an analysis of SWG's proposed revenue level, rate base and rate design?

A. No. Those issues will be addressed in the direct testimony of RUCO witnesses Rodney L. Moore and Marylee Diaz Cortez, C.P.A., the chief of RUCO's Accounting & Rates section. Mr. Moore will sponsor RUCO's recommended levels of required revenue, rate base and rate design. Ms. Diaz Cortez will provide testimony on the Company-proposed conservation margin tracker ("CMT") mechanism and the conceptual concepts that are employed in RUCO's recommended rate design. Both Mr. Moore and Ms. Diaz Cortez will provide testimony on specific operating expense and rate base adjustments.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into three sections. First, I will present the findings of my cost of equity capital analysis, that utilized both the discounted cash flow ("DCF") method, which I believe is the most reliable methodology and the one that I have generally placed the most emphasis on, and the capital asset pricing model ("CAPM"), which I have normally relied on as a check of my DCF results and have also used to make adjustments to my DCF results in certain instances. These are the two most commonly used methods for calculating the cost of equity capital in rate case proceedings and are generally regarded as the most reliable[1]. In this first section I will also provide a brief overview of the current economic climate that SWG is operating in. Second, I will compare my recommended capital structure with the Company-proposed capital structure. Third, I will comment on SWG's cost of capital testimony.

[1] A. Lawrence Kolbe and James A Read Jr., The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press: Cambridge, Massachusetts, 1984, pp. 35-94.

Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of SWG, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 10.15 percent cost of equity capital. This 10.15 percent figure reflects an upward adjustment of 124 basis points to the results derived from my DCF analysis and is 25 basis points lower than the upper range of my estimates obtained from both the DCF and CAPM methodologies.

Cost of Preferred Equity – I am recommending that the Commission adopt an 8.20 percent cost of preferred equity. This figure represents the effective cost of SWG's $100 million issue of trust originated preferred securities ("TOPrS").

Cost of Debt – I am recommending that the Commission adopt a 7.49 percent cost of long-term debt. This is based on my review of the effective costs associated with SWG's various bond issues and credit facilities.

Capital Structure – I am recommending that the Commission adopt the Company-proposed hypothetical capital structure of 53 percent debt, 42 percent common equity and 5 percent preferred equity.

Cost of Capital – Based on the results of my recommended capital structure, cost of common equity, cost of preferred equity and cost of long-term debt analyses, I am recommending an 8.64 percent cost of capital for SWG. This figure represents the weighted cost of the Company's common equity, preferred equity, and long-term debt.

Q. Why do you believe that your recommended 8.64 percent cost of capital is an appropriate rate of return for SWG to earn on its invested capital?

A. The 8.64 percent cost of capital figure that I have recommended meets the criteria established in the landmark Supreme Court cases of Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia (262 U.S. 679, 1923) and Federal Power Commission v. Hope Natural Gas Company (320 U.S. 391, 1944). Simply stated, these two cases affirmed that a public utility that is efficiently and economically managed is entitled to a return on investment that instills confidence in its financial soundness, allows the utility to attract capital, and also allows the utility to perform its duty to provide service to ratepayers. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case guarantees a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as SWG, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your recommended cost of equity capital for SWG?

A. Based on the results of my DCF and CAPM analyses, which ranged from 8.82 percent to 10.39 percent, I am recommending a 10.15 percent cost of equity capital for SWG. My recommended 10.15 percent figure represents a 25 basis point reduction to the extreme upper range of the results that were derived from my cost of common equity analysis.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate SWG's cost of equity capital.

A. The DCF method employs a stock valuation model that is often referred to as either the constant growth valuation model or the Gordon[2] model. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the

[2] Named after Dr. Myron J. Gordon, the professor of finance who developed the model.

dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

$$k = (D_1 \div P_0) + g$$

where: k = the required return (cost of equity, equity capitalization rate),

$D_1 \div P_0$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

g = the expected rate of future dividend growth.

This formula is the basis for the standard growth valuation model that I used to determine SWG's cost of equity capital. It is similar to the model that was used by the Company.

Q. In determining the rate of future dividend growth for SWG, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[3]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

[3] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of \$10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of \$1.00 (\$10.00 book value x 10 percent equity return) and a dividend of \$0.60 (\$1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to \$10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as $g = b \times r$, is also referred to as the internal or sustainable growth rate.

...

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[4] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[5] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rates for earnings and dividends, displayed in the last column, are 16.20 percent. If this rate were to be

[4] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[5] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[6] Dr. Myron Gordon, the individual responsible for the development of the DCF or constant growth model, identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and

[6] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [(BV) ÷ (MP)]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. In theory, the market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. In determining your dividend growth rate estimate, you analyzed the data on ten natural gas LDC's. Why did you use this methodology as opposed to a direct analysis of SWG?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company. Although SWG is publicly traded on the NYSE, SWG's Arizona operations are not. Because of this situation, I created a proxy that includes ten publicly traded natural gas providers that have similar risk characteristics to SWG in order to derive a cost of common equity for the Company.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

Q. What criteria did you use in selecting the ten LDC's that make up your proxy for SWG?

A. Each of the LDC's used in the proxy are followed by The Value Line Investment Survey ("Value Line") and comprise Value Line's natural gas (distribution) industry segment of the U.S. economy. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment A of my testimony contains Value Line's most recent evaluation of the natural gas (distribution) industry.

Q. Are these the same natural gas providers that the Company's cost of capital witness used in SWG's application?

A. Yes, the Company's cost of capital witness, Mr. Frank J. Hanley, included the same natural gas providers in one of two proxy groups that he used for his cost of common equity analysis. The proxy group that contained the ten LDC's that I have used also included a company known as Energen Corporation, which I have decided to exclude from my proxy.

Q. Why did you exclude Energen Corporation from your proxy group?

A. Energen Corporation derives a large portion of its total revenues from oil and natural gas drilling and exploration in areas such as the San Juan (northwestern New Mexico) and Permian (West Texas) basins in addition to operating a LDC in Alabama. Because of this distinction and the fact that Energen is included in Value Line's natural gas (diversified) industry as opposed to the aforementioned natural gas (distribution) industry, I have decided not to include it in my proxy.

Q. Please describe the ten LDC's that make up your sample proxy.

A. The ten LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("ATG"), Cascade Natural Gas Corporation ("CGC"), KeySpan Corp. ("KSE"), Laclede Group, Inc. ("LG"), Nicor Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Peoples Energy Corporation ("PGL"), Piedmont Natural Gas Company ("PNY") South Jersey Industries, Inc. ("SJI") and WGL Holdings, Inc. ("WGL").

The ten LDC's listed above provide natural gas service to customers in the Northeast (i.e. KSE which serves New York and New England), the Middle Atlantic region (i.e. SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast (i.e. ATG which serves Atlanta, Ga., Virginia and Tennessee and PNY which also serves Tennessee and the Carolinas) the Midwest (i.e. PGL and GAS which provide service to Chicago and its suburbs respectively, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. CGC and NWN which serve Washington state and Oregon). Attachment B of my testimony contains Value Line's latest projections on the ten LDC's that I have included in my proxy.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5, titled Dividend Growth Components, provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the period 2000 to 2004. Schedule WAR-5 also includes Value Line's projected 2005, 2006, and 2008-2010 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AGL Resources, Inc., NYSE symbol ATG, as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (page 9) to multiply ATG's earned return on common equity by its earnings retention ratio for each year 2000 through 2004 to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the 2005 internal growth rate and projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, ATG's average internal growth rate of 4.64% over the 2000 - 2004 time frame reflects a steady upward trend that occurred in the first four years of the observation period. From 2000 to 2003 internal growth increased from 1.87% to 6.53%. Internal growth then decreased to 5.45% in 2004. Value

Line is predicting successive increases to 5.53% in 2005, 5.65% in 2006, and 5.85% during the 2008-10 time frame. Despite recent adverse rate request rulings by the Georgia PSC, I believe that a 6.00 percent rate of growth is within the realm of possibility when Value Line's long-term 5.00% earnings, 3.50% dividend, and 8.00% book value growth projections are taken into consideration (Schedule WAR-6).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 illustrates that the number of ATG shares outstanding increased from 54.00 million to 76.70 million during the 2000 to 2004 time frame. Value Line is predicting that this trend will slow to a level of 77.20 million in 2005 before reaching 78.00 million during the 2008-10 period. Based on this data, I believe that a 0.50% growth in shares is not unreasonable for ATG. My final dividend growth rate estimate for ATG is 6.22 percent (6.00 percent internal + 0.22 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average dividend growth rate estimate using the DCF model for the sample LDC's?

A. Based on the DCF model, my average dividend growth rate estimate is 4.76 percent as displayed on Page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate compare to the growth rate data of other publicly traded firms?

A. Overall my estimate of 4.76 percent is higher than the projections of analysts at Value Line but lower than the expectations of brokerages that are surveyed by Zacks Investment Research, Inc. ("Zacks"). Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of both Zacks and Value Line. The 4.76 percent estimate that I have calculated is 111 basis points lower than the projected 5-year EPS average of 5.87 percent by Zacks (as can be seen in Attachment C, Zack's five-year outlook for the natural gas industry as a whole is 8.00 percent) and 41 basis points higher than the 4.35 percent by Value Line (which is an average of projected earnings per share, dividends per share and book value per share). My 4.76 percent estimate is 112 basis points higher than the 3.63 percent 5-year compound historical average also displayed in Schedule WAR-6. This indicates that investors are expecting increased performance from LDC's in the future. On balance, I would say my 4.76 percent estimate is a fair representation of the growth projections that are available to the investing public.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. I used the estimated annual dividends, for the next twelve-month period (through June 2006), which appeared in the most recent Ratings and Reports natural gas (distribution) industry updates of <u>The Value Line</u>

Investment Survey (Attachment B). I then divided that figure by the eight-week average price per share of the appropriate utility's common stock. The eight-week average price is based on the daily closing stock prices for each of the ten utilities in my proxy for the period May 9, 2005 to July 1, 2005. My analysis produced an average dividend yield of 4.15 percent for the ten LDC's included in my sample.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the LDC's included in your sample?

A. As shown in Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 8.91 percent.

Capital Asset Pricing Model (CAPM) Method

Q. Please explain the theory behind the capital asset pricing model ("CAPM") and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe, Ph.D.[7] The CAPM model is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[8] In this regard, CAPM can help an investor to

[7] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[8] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns

determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\,\beta\,(r_m - r_f)\,]$$

where: k = cost of capital of a given security,

r_f = risk-free rate of return,

β = beta coefficient, a statistical measurement of a security's systematic risk,

on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

r_m = average market return (e.g. S&P 500), and

$r_m - r_f$ = market risk premium.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used a six-week average on a 91-day Treasury Bill ("T-Bill") rate.[9] This resulted in a risk-free (r_f) rate of return of 3.04 percent.

Q. Why did you use the short-term T-Bill rate as opposed to the yield on an intermediate 5-year Treasury note or a long-term 30-year Treasury bond?

A. Because a 91-day T-Bill presents the lowest possible total risk to an investor. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a true rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the true rate of interest is subtracted from the total treasury yield, all that remains is the inflationary

[9] A six-week average was computed for the current rate using 91-day T-Bill quotes listed in Value Line's Selection and Opinion newsletter from June 10, 2005 to July 15, 2005.

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the true rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor. Since a 91-day T-Bill presents the lowest possible total risk to an investor, it more closely meets the definition of a risk-free rate of return and is the more appropriate instrument to use in a CAPM analysis.

Q. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical returns on the S&P 500 index from 1926 to 2004 as the proxy for the market rate of return (r_m). The risk premium (r_m - r_f) that results by using the geometric mean calculation for r_m is equal to 7.36 percent (10.40% - 3.04% = <u>7.36%</u>). The risk premium that results by using the arithmetic mean calculation for r_m is 9.36 percent (12.40% - 3.04% = <u>9.36%</u>).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the LDC's used in my sample, were calculated by Value Line and were current as of June 17, 2005. Value Line calculates its betas by using a regression analysis between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the LDC's included in my sample ranged from 0.60 to 1.10 with an average beta of 0.79.

Q. What are the results of your CAPM analysis?

A. As shown on Pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for r_m results in an average expected return of 8.82 percent. My calculation using the arithmetic mean results in an average expected return of 10.39 percent.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

METHOD	RESULTS
DCF	8.91%
CAPM	8.82% – 10.39%

Based on these results, my best estimate of an appropriate range for the cost of equity is from 8.91 percent to 10.39 percent. My final recommendation is a 10.15 percent return for SWG's cost of equity capital.

Q How did you arrive at your recommended 10.15 percent cost of common equity?

A. My recommended 10.15 percent cost of common equity was arrived at by rounding up the 10.39 percent extreme upper end of the results obtained from of my cost of common equity analysis and then reducing that figure by 25 basis points. My recommended cost of equity is 124 basis points higher than the 8.91 percent result derived from my DCF analysis.

Q. Why have you chosen a return on equity that is 124 basis points higher than the results obtained in your DCF analysis and 25 basis points lower than the upper end of your range of cost of equity estimates?

A. Because SWG is more heavily leveraged and faces a higher level of financial risk (i.e. the risk of not being able to meet debt service obligations) than the LDC's included in my proxy, I believe that an appropriate rate of return for the Company lies somewhere near the 10.39 percent upper range of my cost of equity estimates. This upper range estimate is close to the 10.50 percent return on common equity that was adopted by the Nevada Public Utilities Commission during the Company's last rate case proceeding[11] in that state.

My decision to recommend a cost of common equity that is 25 basis points lower than the 10.39 percent high-end figure in my range of estimates was based on RUCO witness Marylee Diaz Cortez's recommendation that the Commission adopt RUCO's recommended rate design, which mitigates income volatility by shifting revenue recovery from SWG's commodity charge to the Company's fixed rate monthly minimum charge, in lieu of adopting the Company-proposed CMT. Ms. Diaz Cortez's recommended rate design recognizes SWG's concerns regarding the Company's ability to recover its revenue requirement if there is a decline in customer consumption. If the Commission adopts RUCO's recommended rate design, the Company will face a lower level of risk due to income volatility and therefore will not require a higher return on equity. Accordingly, I have reduced my high-end estimate by the same 25 basis points that the Company's cost of capital consultant, Mr. Hanley, is advocating in regard to his recommended cost of common equity as it relates to the CMT.

To a lesser degree, my decision to recommend a 10.15 percent cost of common equity, that is 124 basis points higher than the results I obtained

[11] Nevada Public Utilities Commission Docket No. 04-3011

from my DCF analysis, was based on SWG's inability to achieve higher levels of shareholder equity since the Company's last rate case proceeding, and my comparison of Value Line projections for the LDC's in my proxy against the Value Line projections for SWG. The combination of my upwardly adjusted DCF result and the use of a hypothetical capital structure, comprised of 53 percent debt, 5 percent preferred equity and 42 percent common equity, provides SWG with a higher weighted cost of equity.

Q. What percentage of debt and equity comprise SWG's actual capital structure?

A. The Company's actual capital structure during the Test Year was comprised of 61 percent debt, 5 percent preferred equity and 34 percent common equity. SWG's capital structure has a higher level of debt than the capital structures of the ten LDC's that I included in my DCF and CAPM proxies (Schedule WAR-9).

...

Q. What is the difference between your recommended weighted cost of capital, using your recommended 10.15 percent cost of common equity and your recommended hypothetical capital structure, and the weighted cost of capital that results from using your recommended 10.15 percent cost of common equity in the Company's actual capital structure?

A. The use of my 10.15 percent cost of common equity in my recommended hypothetical capital structure results in a weighted cost of capital of 8.64 percent. The use of my recommended cost of equity in SWG's actual capital structure results in a weighted cost of capital of 8.43 percent or a difference of 21 basis points.

Q. How does SWG's beta coefficient compare to the average beta coefficient that you used in your CAPM analysis?

A. SWG's beta coefficient is 0.75 as opposed to the average beta of 0.79 that I used in my CAPM analysis (Attachment C).

Q. What would the expected return on equity for SWG be if you substituted SWG's beta into your CAPM models using both a geometric and arithmetic mean?

A. Substituting a 0.75 beta into the models produces results that are identical to those obtained for four of the LDC's that I included in my proxy group (Cascade Natural Gas Corp., Laclede Group, Inc., Piedmont Natural Gas Company, and WGL Holdings, Inc.). As exhibited on pages 1 and 2 of schedule WAR-7, the expected return for those four LDCs is 8.56 percent, using a geometric mean, and 10.06 percent, using an arithmetic mean. My recommended cost of equity for SWG of 10.15 percent is 159 basis points higher than the low end (geometric mean) of the CAPM results that I have just described and 9 basis points higher than the high end (arithmetic mean).

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are investing in non-regulated entities also.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. Economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[12] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate

[12] The interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy over the last four years?

A. The U.S. economy entered into a recession around the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including Value Line, believed that the Federal Reserve Chairman was cutting rates in the hope of avoiding the recession that the U.S. is still in the process of recovering from.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates, moves which indicated that the worst may be over and that the current recession might have bottomed out during the last quarter of 2001, a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in 45 years.

Even though some signs of economic strength, that were mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC stated "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'"[13]

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. Between June 29, 2004 and June 30, 2005, the FOMC has raised the federal funds rate eight more times to its current level of 3.25 percent (the next scheduled meeting of the FOMC will be on August 9,

[13] Wolk, Martin, "Fed leaves short-term rates unchanged," MSNBC, January 28, 2004.

2005). As expected, banks have followed the Fed's lead and have boosted the prime rate to its current level of 6.25 percent. According to an article that appeared in the September 22, 2004 edition of the The Wall Street Journal, the FOMC's decision to begin raising rates was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy[14]. In other words, the Fed is trying to head off inflation *before* it becomes a problem.

Since it began increasing the federal funds rate in June 2004, the Federal Reserve has stated that it would increase rates at a "measured" pace.

Many analysts and economists interpret this language to mean that Chairman Greenspan will be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates resulted in financial turmoil, which contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[15].

[14] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[15] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Putting this all into perspective, how have the Fed's actions over the past four years affected benchmark rates?

A. Virtually all of the benchmark rates have fallen to levels not seen in over forty-five years. The Fed's actions have had the overall effect of reducing the cost of many types of business and consumer loans. Despite the recent increases in the federal funds rate, the federal discount rate (the rate charged to member banks) has fallen from 5.73 percent in 2000, to its present level of 4.25 percent. Despite the recent increases, rates are still at historically low levels.

Q. What has been the trend in other leading interest rates over the last year?

A. As of July 15, 2005, all of the leading interest rates have edged up. The prime rate has increased from 4.25 percent a year ago to a current level of 6.25 percent. The benchmark federal funds rate, just discussed, has increased from 1.25 percent, in July 2004, to its current level of 3.25 percent (the result of the nine quarter point increases noted earlier). The yields on all maturities of U.S. Treasury instruments, with the exception of the 10-year, 30-year and 30-year zero coupon bonds, which have fallen 41, 90, and 109 basis points respectively since July 2004, have increased over the past year. This unusual situation, in which long-term rates are falling as short-term rates are rising, is creating a flat yield curve that has been described by Chairman Greenspan as a "conundrum."[16] The 91-day

[16] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

T-bill rate, used in my CAPM analysis, has increased from 1.26 percent, in July 2004, to 3.14 percent today. The 1-Year Treasury Constant Maturity rate has also increased from 2.00 percent over the past year to 3.55 percent today. Again, these levels are still low when they are compared with the historical yields displayed on Schedule WAR-8.

Q. How have economists and members of the investment community viewed the Fed's rate actions since June 2004?

A. The change in the Fed's language from "considerable period" to "patient" to "measured," that have been noted through the course of my testimony, has pretty much summed up the Fed's course of action during the economic recovery that is still in progress. In his October 2004 column for Wells Capital Management's ("Wells") Monthly Market Outlook publication, Senior Economist Gary E. Schlossberg viewed the Fed's recent credit tightening action as a trend that is likely to continue barring an unraveling of the economic recovery, a major disruption in the financial markets or a renewed threat of declining prices. According to Mr. Schlossberg, the Fed appears to be determined to engineer a fundamental shift from its past policy of "aggressive accommodation" to what he considers to be a more "neutral" policy stance (determined by both the rate of inflation and an additional "premium" of possibly 1.00 percent to 1.50 percent) via a series of rapid fire quarter-point increases that will result in a federal funds rate of 4.00 percent to 4.50 percent by the end of 2005. Mr. Schlossberg's expectation of future incremental increases in the federal funds rate was shared by Mickey Levy, Chief Economist for Bank of America, and by Value Line analysts. In the October 1, 2004 edition of Value Line's "Selection & Opinion" publication, Value Line's analysts stated that they believed that the Fed was following a prudent course. In their opinion the Fed's interest rate cutting helped to avoid a more serious recession and the Fed's present course of action will help to insure that the current upturn in the economy is sustained while keeping inflation low and under control at the same time. Although the increases in the federal funds rate have been viewed as a positive development (i.e. evidence of a strengthening economy), the upward movements in crude oil prices have not. Rising crude oil prices have become a serious concern to analysts and economists because of their potential adverse impact on corporate earnings.

Q. What is the current outlook for interest rates and the economy?

A. The views expressed by Messrs Levy and Schlossberg during the last quarter of 2004 appear to have been on target. A Reuters article[17], published on Sunday, July 17, 2005, quoted former Federal Reserve Governor Lyle Gramley as stating that, in an upcoming meeting with congressional leaders, Chairman Greenspan (who will retire from the Fed at the end of January, 2006) "...will give no indication at all that the Fed is

[17] Bull, Alister, "Greenspan, at end of era, to signal more rate rises," Reuters, July 17, 2005.

near the end of raising short-term interest rates". Mr. Gramley, who is now at the Washington-Stanford Research Group, went on to say "Quite the contrary. I think he will caution Congress on the need to continue raising interest rates". The article also quoted the presidents of the Richmond and San Francisco Federal Reserve Banks who believe that the FOMC will continue its present course of action. Goldman Sachs' chief U.S. economist Bill Dudley was quoted as saying that he is forecasting that the Fed Funds rate, as projected by Mr. Schlossberg, will hit the 4.5 percent figure next year.

According to analysts and economists at both Value Line and Wells, the overall outlook for economic growth, and the current low interest rate environment, appears to be good despite a moderate pace of GDP growth. In their most recent Selection & Opinion outlook published on Friday, July 15, 2005, Value Line analysts had little to add to the comments that appeared in the June 10, 2005 quarterly economic review, in which they stated the following:

> "This modest rate of GDP growth is unlikely to rekindle wide-spread inflationary pressures. To be sure, there has been a pickup in pricing in the energy area, where quotations for oil are close to a record high. On the whole, though, inflation continues to be held in check, with solid gains in productivity (or labor cost efficiency) being instrumental in helping maintain this relative pricing stability. Here as well, we think these benign trends will remain in place. Such moderation, plus the sluggish rate of employment growth, should dissuade the Federal Reserve from raising interest rates aggressively."

The following quote[18] by Wells' Chief Investment Strategist, James W. Paulsen, Ph.D., had this to say:

> "Most importantly, prior to every major economic slowdown or recession in the last 25 years, long-term bond yields rose significantly. This simply has not yet occurred in the contemporary cycle. Not only did long-term yields decline in the last recession to levels not seen in about four decades, they have yet to sustain any meaningful rise above these very low levels. Even the hikes of short-term interest rates by the Fed appear timid. Thus far they have been lifted little more than the rise in the core rate of consumer inflation, leaving the real Fed funds rate virtually unchanged. It may be that the Fed has been raising short-term yields, but the odd if not unique imperviousness of long-term yields to Fed action suggest interest rate policy has not been very (if at all) restrictive."

Q. How do Value Line's analysts view the impact of the Federal Reserve's interest rate actions on the natural gas (distribution) segment of the U.S. economy?

A. In his June 17, 2005 update on the natural gas (distribution) segment, Value Line analyst Evan I. Blatter, stated the following:

> The stocks in this industry offer income-oriented investors good stock price stability. With the volatility of the stock market in recent years, many investors have grown concerned over the value of their nest eggs. For conservative, income-oriented investors, many stocks in this industry have a lot to offer, not the least of which is a steady stream of income. Indeed, most of these shares offer above-average dividend yields compared to the rest of the stocks covered in the *Value Line Investment Survey*. Should interest rates continue to go up, however, other income-oriented investments may become more attractive and cause some downward pressure on the industry.

. . .

[18] Wells Capital Management's Economic and Market Perspective, April 2005, Pages 1.

Q. What are Value Line analyst's projections for return on common equity for the LDC's in your sample and the natural gas (distribution) segment as a whole?

A. For my sample group of LDC's, Value Line's analysts are projecting returns on common equity ("ROE") that range from 7.5 percent to 13.5 percent over the 2005 to 2010 time frame. Value Line's ROE projections for the industry as a whole range from 12.0 percent to 12.5 percent over the same period (Attachment A).

Q. Please summarize how the economic data just presented relates to SWG.

A. The current benign rate of inflation translates into stable and even possibly declining prices for goods and services, which in turn means that SWG can expect its present operating expenses to either remain stable or possibly decline in the coming years. Lower interest rates would also benefit SWG in regard to any short or long-term borrowing needs that the Company may have. Lower interest rates would further help to accelerate growth in new construction projects and home developments (which have been on an upward trend according to data presented in Value Line) in the Company's service territory, and may result in new revenue streams to SWG.

Q. After weighing the economic information that you've just discussed, do you believe that the 10.15 percent cost of equity capital that you have estimated is reasonable for SWG?

A. I believe that my recommended 10.15 percent cost of equity will provide SWG with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are still low by historical standards), continued growth in new housing construction (attributed to historically low interest rates), and the low and stable outlook for inflation are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my DCF and CAPM analyses have produced such a return. The results that I have obtained are consistent with Value Line's view that the LDC stocks included in my proxy "offer an above average dividend yield." In fact, my recommended 10.15 percent cost of common equity exceeds Value Line's return on common equity projections for SWG by 415 basis points during the 2005 time frame and by 15 basis points over the 2005 to 2010 time frame (Attachment C).

CAPITAL STRUCTURE

Q. Have you reviewed SWG's testimony regarding the Company's proposed capital structure?

A. Yes, I have.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a hypothetical capital structure comprised of approximately 53 percent long-term debt, 5 percent preferred equity and 42 percent common equity.

Q. What capital structure are you proposing for SWG?

A. I have adopted the Company-proposed hypothetical capital structure.

Q. Is SWG's proposed hypothetical capital structure in line with industry averages?

A. Yes. As can be seen in Schedule WAR-9, the hypothetical capital structure being proposed by SWG is close to the average debt and equity percentages of my sample group of LDC's. The capital structures for those utilities averaged 51.2 percent for long-term debt, 0.3 percent for preferred equity, and 48.5 percent for common equity.

Q. Is SWG's actual capital structure in line with industry averages?

A. No. As discussed earlier, SWG's capital structure is heavier in debt than the capital structures of the other LDC's included in my cost of capital analysis (Schedule WAR-9).

Q. In terms of risk, how does SWG's capital structure compare to the LDC's in your sample?

A. The LDC's in my sample would be considered as having a lower level of financial risk (i.e. the risk associated with debt repayment) because of their lower levels of debt. The lower financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived from my DCF analysis is applicable to LDC's that are less leveraged and, theoretically speaking, not as risky as a utility with a level of debt similar to SWG's. In the case of a publicly traded company, such as those included in my proxy, a company with SWG's level of debt would be perceived as having a higher level of financial risk and would therefore also have a higher expected return on common equity.

Q. Have you made an upward adjustment to your DCF estimate based on this perception of higher financial risk?

A. Yes. As I also explained earlier, I have made an upward adjustment to my recommended cost of equity based on the results of my DCF and CAPM analyses.

...

Q. Have you accepted the Company-proposed 7.49 percent cost of long-term debt?

A. Yes I have. However, I do want to point out that the Company-proposed cost of long-term debt is somewhat overstated because the effective cost of two of the Company's debt issuances (i.e. the 7.5 % debenture, due on August 1, 2006, and the 8.0% debenture, due on August 1, 2026) were calculated on amounts that contain reacquisition costs related to SWG's purchase and sale of PriMerit Bank, an unregulated subsidiary that the Company sold sometime in the early 1990's.

Q. Why have you decided not to make an adjustment to the effective cost of these issues?

A. RUCO consultant Stephen G. Hill made light of this same issue during the Company's prior rate case proceeding in 2000. During that proceeding Mr. Hill pointed out that the effective cost of the two issues in question should be adjusted downward from 8.96 percent to 8.34 percent and 8.89 percent to 8.49 percent respectively, by cutting the reacquisition costs on these two issues in half (which would result in a 50/50 sharing of the costs between SWG and the Company's ratepayers). Mr. Hill eventually decided not to make such an adjustment since the Commission did not adopt his recommendation in a prior SWG rate case. I also have not made this adjustment, and have adopted the Company-proposed hypothetical capital structure and cost of debt of 7.49 percent

Q. Have you accepted the Company-proposed 8.20 percent cost of preferred equity?

A. Yes I have.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.95 percent cost of equity capital proposed by the Company's cost of capital witness, which assumes that the Commission will reject the Company-proposed CMT, is 180 basis points higher than the 10.15 percent cost of equity capital that I am recommending. The 11.70 percent cost of equity capital proposed by the Company's cost of capital witness, which assumes that the Commission will adopt the Company-proposed CMT, is 155 basis points higher than the 10.15 percent cost of equity capital that I am recommending.

Q. How does the Company's proposed weighted cost of capital compare with your recommended weighted cost of capital?

A. The Company has proposed a weighted cost of capital of 9.40 percent. This composite figure is the result of a weighted average of SWG's proposed 7.49 percent cost of long-term debt, 8.20 percent cost of preferred equity and the aforementioned 11.95 percent cost of equity capital (which assumes the Commission will reject the Company-proposed CMT). The Company-proposed 9.40 percent weighted cost of capital is

76 basis points higher than the 8.64 percent weighted cost that I am recommending.

COMMENTS ON SWG'S COST OF EQUITY CAPITAL TESTIMONY

Q. Please describe SWG's cost of equity capital testimony.

A. As noted earlier in my testimony, SWG's cost of capital testimony was prepared by the Company's cost of equity consultant Mr. Frank J. Hanley. Mr. Hanley's testimony presents the results of his cost of common equity analysis, which used the DCF, risk premium, CAPM, and comparable earnings methodologies. Mr. Hanley believes that the Company is entitled to an 11.95 percent cost of equity if the Commission rejects the Company-proposed CMT. Should the Commission approve the Company-proposed CMT, Mr. Hanley believes that an 11.70 percent cost of common equity is appropriate.

Q. Please compare the way you conducted your DCF analysis with the way that Mr. Hanley conducted his.

A. Mr. Hanley conducted a DCF analysis using the same single-stage constant growth model as I did. As I explained earlier in my testimony, Mr. Hanley also conducted his analysis using two separate proxy groups. His first proxy group included all of the LDC's that I included in mine plus Energen Corporation. His second proxy group is comprised of five LDC's and include the following: AGL Resources, Inc., Cascade Natural Gas

Corporation, Nicor Inc., Northwest Natural Gas Co., and Piedmont Natural Gas Company. In addition to the aforementioned proxy groups, Mr. Hanley also treated SWG as a stand-alone company in his analysis.

Q. How did Mr. Hanley determine the dividend yield component in his DCF model?

A. For the $\mathbf{P_0}$ portion of the DCF formula, Mr. Hanley averaged spot prices that occurred on October 1, 2004 with average high and low prices that occurred during the months of August 2004 and September 2004 to arrive at initial dividend yields of 4.18 percent for his proxy group of eleven LDC's and 4.34 percent for his group of five LDC's. His initial dividend yield results range from 3 to 19 basis points higher than the average 4.15 percent dividend yield that I obtained using an average of closing stock prices during a more recent an 8-week period. After obtaining the aforementioned initial dividend yields, Mr. Hanley then makes an upward adjustment, that is equal to fifty percent of the average projected five-year growth rate in earnings per share for each of the LDC's in his proxies, to arrive at his final dividend yields of 4.28 percent for his proxy group of eleven LDC's and 4.44 percent for his group of five LDC's. His final dividend yield estimate results range from 13 to 29 basis points higher than the average 4.15 percent dividend yield that I obtained using an average of closing stock prices during a more recent 8-week period.

Q. How did Mr. Hanley obtain his final growth or **g** estimate in his DCF analysis?

A. Mr. Hanley averaged the long-term (i.e. 2007-09) September 2004 earnings per share projections of Value Line analysts and the October 2004 five-year earnings per share projections of Thompson FN/First Call analysts to arrive at average DCF growth rates of 4.93 percent for his proxy group of eleven LDC's and 4.80 percent for his group of five LDC's. His final DCF growth estimate results range from 4 to 17 basis points higher than the average 4.76 percent dividend yield that I obtained.

Q. What is the average DCF result for the average dividend yields and growth estimates that were obtained by Mr. Hanley?

A. Mr. Hanley's average DCF costs of equity are 9.21 percent for his proxy group of eleven LDC's and 9.24 percent for his group of five LDC's. These results range from 30 to 33 basis points higher than my DCF cost of equity of 8.91 percent. However, Mr. Hanley's final DCF cost of equity estimates range from 10.36 percent for his proxy group of eleven LDC's and 10.20 percent for his group of five LDC's. Mr. Hanley's final DCF cost of equity estimate ranges from 129 to 217 basis points higher than the average 8.91 percent DCF cost of equity that I obtained. His stand-alone result for SWG is 10.69 percent.

Q. How did Mr. Hanley obtain his final DCF cost of equity estimates of 10.20 percent to 10.36 percent when his average results indicate a range of 9.21 percent to 9.24 percent?

A. To arrive at his final DCF cost estimates, Mr. Hanley ignored any results that were lower than 9.90 percent, which he states was the lowest rate awarded to a gas distribution utility between January 1, 2003 and June 4, 2004. This decision eliminated the results of seven of the LDC's in his proxy group of eleven and three of the LDC's in his proxy group of five and produces a higher DCF cost of equity estimate.

Q. Did you conduct a risk premium analysis?

A. No.

Q. Please compare the results of your CAPM analysis with the results of Mr. Hanley's CAPM analysis.

A. Mr. Hanley performed two CAPM analyses, one using the traditional CAPM model which I used (i.e. $k = r_f + [\ ß\ (r_m - r_f)]$) and a second using the empirical ("ECAPM") version of the model which assumes that the risk-free rate of return used in the traditional model is understated.

Q. Why didn't you use the ECAPM version in your CAPM analysis?

A. As I stated earlier in my testimony, the Value Line betas that I used in my CAPM model are adjusted by Value Line for their long-term tendency to converge toward 1.00. This eliminates the need to use the ECAPM version, which assumes that an upward adjustment is required for the risk-free rate of return.

Q. What were the differences between your CAPM analysis and Mr. Hanley's CAPM analysis?

A. Mr. Hanley performed his analysis using the same two proxies that he used in his DCF analyses and also treated SWG as a stand-alone entity. His CAPM analysis produced an average expected return, or **k,** of 11.08 percent for his group of eleven LDC's and 11.29 percent for his group of five LDC's. His results ranged from 69 to 90 basis points higher than my 10.39 percent CAPM analysis result using an arithmetic mean, and 226 to 247 basis points higher than my 8.82 percent CAPM analysis result using a geometric mean. His stand-alone result for SWG is 11.37 percent. Mr. Hanley's ECAPM analysis produced an average expected return of 11.41 percent for his group of eleven LDC's and 11.68 percent for his group of five LDC's. His results ranged from 102 to 129 basis points higher than my 10.39 percent CAPM analysis result using an arithmetic mean, and 259 to 286 basis points higher than my 8.82 percent CAPM analysis result using a geometric mean. His ECAPM result for SWG as a stand-alone entity is 11.73 percent. Again, in calculating his final average, Mr. Hanley ignored any expected returns that were 9.90 percent or lower.

Q. What beta coefficient (ß) did you use in your CAPM model and what beta coefficient did Mr. Hanley's use in his CAPM analysis?

A. I used a beta coefficient of 0.79, which is an average of Value Line's adjusted betas for the ten LDC's included in my proxy. Mr. Hanley used an average beta coefficient of 0.74 for his group of eleven LDC's and an average beta coefficient of 0.79 in his group of five LDC's. Mr. Hanley also used the adjusted betas published by Value Line at the time he performed both his CAPM and ECAPM his analyses. Technically, Mr. Hanley's ECAPM model overstates the expected return because of his use of an adjusted beta in a model that contains an upward adjustment for the risk-free rate of return.

Q. Please compare the risk free rate of return (r_f) proxies used in both your and Mr. Hanley CAPM analyses.

A. As I explained earlier in my testimony (page 25), I used a six-week average on a 91-day T-Bill rate. This resulted in a risk-free rate of return of 3.04 percent. Mr. Hanley on the other hand, used an average of economist's projections on the yields of 20-year U.S. Treasury bonds for the six quarters ending with the first calendar quarter of 2006. This resulted in a higher risk-free rate of return of 5.52 percent. The difference between the two average yields is 248 basis points.

Q. What is the difference between your market risk premium and the market risk premium used by Mr. Hanley?

A. Mr. Hanley derived his return on the market figure of 12.83 percent by averaging Value Line and Ibbotson Associates data. His risk premium of 7.31 percent was derived by subtracting his 5.52 percent risk free rate of return from his calculated 12.83 percent return on the market. The 7.31 percent market risk premium used by Mr. Hanley is 205 basis points lower than my 9.36 percent market risk premium, using an arithmetic mean, and is 5 basis points lower than my 7.36 percent market risk premium, using a geometric mean.

Q. Did you perform a comparable earnings analysis, which included non-regulated companies, similar to the one performed by Mr. Hanley?

A. No.

Q. How does Mr. Hanley arrive at his 11.95 percent cost of common equity figure after presenting the results of his DCF, risk premium, CAPM and comparable earnings analyses?

A. Mr. Hanley arrived at his recommended 11.95 percent cost of common equity by equally weighting the results of all four of his models. This resulted in average cost rates of 11.31 percent for his proxy group of eleven LDC's, 11.59 for his group of five LDC's and 11.85 percent for SWG as a stand-alone entity. After this he makes two further upward adjustments, one based on bond rating differences and the other to take into account SWG's lack of a weather normalization clause. These additional upward adjustments result in estimates of 11.87 percent for his group of eleven LDC's and 12.10 percent for his group of five LDC's. His final recommended cost of common equity of 11.95 percent is an average of the aforementioned estimates for the two proxy groups and the 11.85 percent cost for SWG. Mr. Hanley's 11.95 percent recommended cost of equity, assuming the Commission rejects the Company-proposed CMT, is 180 basis points higher than my recommended 10.15 percent return on common equity. His recommended cost of 11.70 percent equity, assuming the Commission adopts the Company-proposed CMT, is 155 basis points higher than my recommended 10.15 percent return on common equity.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Hanley constitute your acceptance of his positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on SWG?

A. Yes, it does.

Qualifications of William A. Rigsby

EDUCATION:

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

EXPERIENCE:

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Revenue Auditor II
Arizona Department of Revenue
Corporate Income Tax Audit Unit
Phoenix, Arizona
November 1993 – October 1994

Tax Examiner Technician I
Arizona Department of Revenue
Transaction Privilege Tax Audit Unit
Phoenix, Arizona
July 1991 – November 1993

Appendix 1

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.	Type of Proceeding
ICR Water Users Association	U-2824-94-389	Original CC&N
Rincon Water Company	U-1723-95-122	Rate Increase
Ash Fork Development Association, Inc.	E-1004-95-124	Rate Increase
Parker Lakeview Estates Homeowners Association, Inc.	U-1853-95-328	Rate Increase
Mirabell Water Company, Inc.	U-2368-95-449	Rate Increase
Bonita Creek Land and Homeowner's Association	U-2195-95-494	Rate Increase
Pineview Land & Water Company	U-1676-96-161	Rate Increase
Pineview Land & Water Company	U-1676-96-352	Financing
Montezuma Estates Property Owners Association	U-2064-96-465	Rate Increase
Houghland Water Company	U-2338-96-603 et al	Rate Increase
Sunrise Vistas Utilities Company – Water Division	U-2625-97-074	Rate Increase
Sunrise Vistas Utilities Company – Sewer Division	U-2625-97-075	Rate Increase
Holiday Enterprises, Inc. dba Holiday Water Company	U-1896-97-302	Rate Increase
Gardener Water Company	U-2373-97-499	Rate Increase
Cienega Water Company	W-2034-97-473	Rate Increase
Rincon Water Company	W-1723-97-414	Financing/Auth. To Issue Stock
Vail Water Company	W-01651A-97-0539 et al	Rate Increase
Bermuda Water Company, Inc.	W-01812A-98-0390	Rate Increase
Bella Vista Water Company	W-02465A-98-0458	Rate Increase
Pima Utility Company	SW-02199A-98-0578	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Pineview Water Company	W-01676A-99-0261	WIFA Financing
I.M. Water Company, Inc.	W-02191A-99-0415	Financing
Marana Water Service, Inc.	W-01493A-99-0398	WIFA Financing
Tonto Hills Utility Company	W-02483A-99-0558	WIFA Financing
New Life Trust, Inc. dba Dateland Utilities	W-03537A-99-0530	Financing
GTE California, Inc.	T-01954B-99-0511	Sale of Assets
Citizens Utilities Rural Company, Inc.	T-01846B-99-0511	Sale of Assets
MCO Properties, Inc.	W-02113A-00-0233	Reorganization
American States Water Company	W-02113A-00-0233	Reorganization
Arizona American Water Company	W-01303A-00-0327	Financing
Arizona Electric Power Cooperative	E-01773A-00-0227	Financing
360networks (USA) Inc.	T-03777A-00-0575	Financing
Beardsley Water Company, Inc.	W-02074A-00-0482	WIFA Financing
Mirabell Water Company	W-02368A-00-0461	WIFA Financing
Rio Verde Utilities, Inc.	WS-02156A-00-0321 et al	Rate Increase/ Financing
Arizona Water Company	W-01445A-00-0749	Financing
Loma Linda Estates, Inc.	W-02211A-00-0975	Rate Increase
Arizona Water Company	W-01445A-00-0962	Rate Increase
Mountain Pass Utility Company	SW-03841A-01-0166	Financing
Picacho Sewer Company	SW-03709A-01-0165	Financing
Picacho Water Company	W-03528A-01-0169	Financing
Ridgeview Utility Company	W-03861A-01-0167	Financing
Green Valley Water Company	W-02025A-01-0559	Rate Increase
Bella Vista Water Company	W-02465A-01-0776	Rate Increase
Arizona Water Company	W-01445A-02-0619	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Arizona-American Water Company	W-01303A-02-0867 et al.	Rate Increase
Arizona Public Service Company	E-01345A-03-0437	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-03-0434	Rate Increase
Qwest Communications, Inc.	T-01051B-03-0454 et al.	Price Cap Plan
Chaparral City Water Company, Inc.	W-02113A-04-0616	Rate Increase
Arizona Water Company	W-01445A-04-0650	Rate Increase
Tucson Electric Power	E-01933A-04-0408	Rate Review

ATTACHMENT A

The Natural Gas Distribution Industry's Timeliness rank has fallen one notch since our last report in March: 96 (of 98). March-period earnings for most of the gas utilities we cover were down year over year as a result of milder temperatures across most of the United States. This will likely affect full-year earnings since most of these distribution companies' profits are derived during the winter quarters (March and December).

Regulated Utilities

The key features of gas-utility stocks are their safety and better-than-average dividend yields, *not* price performance or appreciation potential. Local distribution companies (LDCs) are natural gas utilities that are regulated by both individual state and/or federal regulatory agencies. They are considered natural monopolies since it is more cost-efficient to build one pipeline system to serve a region, versus multiple distributors competing over the same location. As a result of the government allowing each company to operate essentially as a monopoly, regulators set allowable rates of return that each company is able to earn. Should earnings be less than the permitted rate, the company is able to petition regulators for higher rates. This has been the case at *SEMCO*, which has received a $7 million-per-year increase in Michigan. *Southern Union* received a $22.5 million rate increase at its Missouri Gas Light Energy unit, and is petitioning for an additional increase. These increases will likely lead to higher profit levels at these companies. However, should distributors earn profits in excess of their allowable rates over an extended period, they may be subject to a regulatory review. If it is determined that they are in fact exceeding their permitted rates, they may be subject to a rate reduction.

Nonregulated Activities

The gas distribution industry has experienced some changes over the past decade. In 1992, The Federal Energy Regulatory Commission, instituted Order 636, which required pipeline operators to unbundle transportation and storage services, along with guaranteeing gas marketers access to their distribution networks. As a result, many distribution companies have entered into activities outside of their core distribution operations. These activities include retail-energy marketing, energy trading, and oil and gas exploration and production. *Piedmont Natural Gas*, for example, intends to grow its nonregulated segment to at least 15% of total earnings. In fact, most companies in this industry have some portion of their earnings coming from nonregulated operations, and are looking to boost their percentage of earnings from this segment in the coming years. Furthermore, as profits in nonregulated operations rise, regulatory agencies seem less likely to give out rate increases. This is the tradeoff they face, as nonregulated activities have no restrictions on their return on equity.

INDUSTRY TIMELINESS: 96 (of 98)

Natural gas prices

The higher natural gas prices of late have primarily benefited those companies that are involved in nonregulated activities. In fact, gas distributors are actually hurt by rising gas prices. They continue to earn their allowable return on equity, but the added costs of gas are passed onto customers. This can sometimes result in the loss of customers, additional conservation among customers, along with an increase in bad debt expense.

Conservative Investment

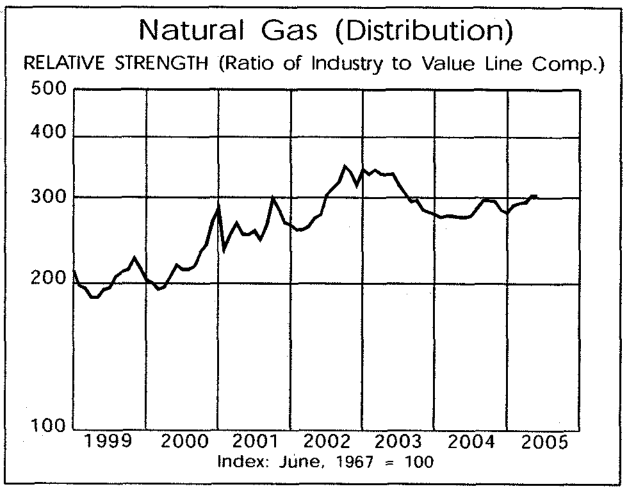
The stocks in this industry offer income-oriented investors good stock-price stability. With the volatility of the stock market in recent years, many investors have grown concerned over the value of their nest eggs. For conservative, income-oriented investors, many stocks in this industry have a lot to offer, not the least of which is a steady stream of income. Indeed, most of these shares offer above-average dividend yields compared to the rest of the stocks covered in *The Value Line Investment Survey*. Should interest rates continue to go up, however, other income-oriented investments may become more attractive and cause some downward pressure on the industry

Still, there is great deal of diversity in constituents of this industry. The biggest differences are usually seen with nonregulated business segments. As companies shift toward these businesses, they increase the potential for capital appreciation and risk of capital loss. Moreover, companies making a concerted push to nonregulated businesses may be less generous with dividend increases, preferring to use money to build new ventures rather than pay it out to shareholders. Investors should pay close attention to this factor when making commitments here.

Evan I. Blatter

Composite Statistics: Natural Gas (Distribution)

2001	2002	2003	2004	2005	2006		08-10
27611	22947	29981	33220	**35000**	**37950**	Revenues ($mill)	**42000**
1070.4	1231.5	1395.3	1735.9	**1750**	**1850**	Net Profit ($mill)	**2100**
39.7%	35.3%	37.4%	35.6%	**36.0%**	**36.0%**	Income Tax Rate	**36.0%**
3.9%	5.4%	4.7%	5.2%	**5.0%**	**4.9%**	Net Profit Margin	**5.0%**
57.4%	57.8%	55.9%	53.2%	**53.0%**	**53.0%**	Long-Term Debt Ratio	**52.5%**
41.5%	41.4%	43.7%	45.7%	**45.0%**	**45.0%**	Common Equity Ratio	**45.5%**
24342	24907	28436	31268	**33500**	**35400**	Total Capital ($mill)	**39450**
24444	25590	31732	32053	**33500**	**35000**	Net Plant ($mill)	**40000**
6.1%	6.6%	6.4%	7.1%	**7.0%**	**7.0%**	Return on Total Cap'l	**7.0%**
10.3%	11.7%	11.1%	11.9%	**12.0%**	**12.0%**	Return on Shr. Equity	**12.5%**
10.5%	11.8%	11.2%	12.0%	**12.0%**	**12.0%**	Return on Com Equity	**12.5%**
2.5%	3.9%	4.1%	5.5%	**5.5%**	**5.5%**	Retained to Com Eq	**5.5%**
76%	68%	64%	55%	**60%**	**60%**	All Div'ds to Net Prof	**60%**
16.8	14.8	14.1	13.6	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	**13.0**
.86	.81	.80	.72			Relative P/E Ratio	**.87**
4.5%	4.5%	4.5%	4.0%			Avg Ann'l Div'd Yield	**4.6%**
244%	280%	314%	308%	**315%**	**330%**	Fixed Charge Coverage	**375%**



ATTACHMENT B

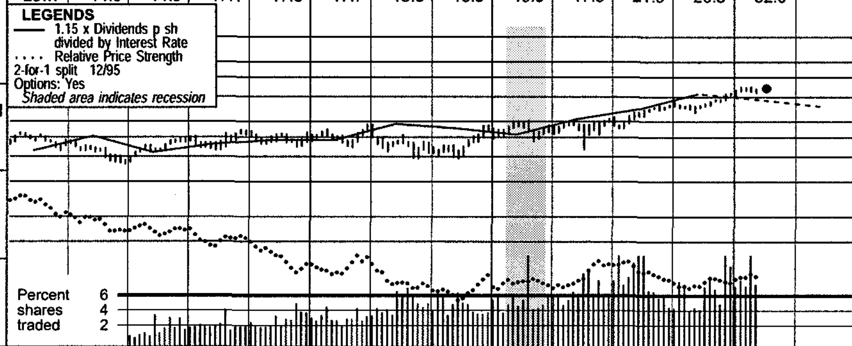
AGL RESOURCES NYSE-ATG

RECENT PRICE	35.30	P/E RATIO	15.3 (Trailing: 14.6 / Median: 14.0)	RELATIVE P/E RATIO	0.84	DIV'D YLD	3.5%	VALUE LINE

TIMELINESS 3 Raised 2/4/05
SAFETY 2 New 7/27/90
TECHNICAL 3 Lowered 1/7/05
BETA .85 (1.00 = Market)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	19.4	20.0	22.0	21.6	23.4	23.4	23.2	24.5	25.0	29.3	33.7	36.3
Low:	14.6	14.9	17.1	17.8	17.7	15.6	15.5	19.0	17.3	21.9	26.5	32.0

Target Price Range
2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+25%)	9%
Low	35	(Nil)	4%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	4	2	2	3	2	2	2	0
to Sell	0	4	2	2	2	2	2	2	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	91	128	119
to Sell	53	50	69
Hld's(000)	36912	48181	48662

Percent shares traded 6 4 2

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.6	11.0
3 yr.	74.3	39.9
5 yr.	150.0	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
21.63	22.58	20.26	20.43	22.73	23.59	19.32	21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	***31.10***	***32.25***	Revenues per sh A	***37.20***
1.93	2.04	2.07	2.31	2.25	2.24	2.33	2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	***3.95***	***4.10***	"Cash Flow" per sh	***4.60***
.95	1.01	1.04	1.13	1.08	1.17	1.33	1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	***2.30***	***2.40***	Earnings per sh A B	***2.75***
.94	.98	1.02	1.03	1.04	1.04	1.04	1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	***1.24***	***1.27***	Div'ds Decl'd per sh C■	***1.35***
2.65	2.73	2.95	2.74	2.49	2.37	2.17	2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	***3.30***	***2.75***	Cap'l Spending per sh	***2.25***
8.83	8.97	9.42	9.70	9.90	10.19	10.12	10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	***19.10***	***20.15***	Book Value per sh D	***23.90***
43.40	44.32	47.57	48.69	49.72	50.86	55.02	55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	***77.20***	***77.50***	Common Shs Outst'g E	***78.00***
13.7	14.2	15.3	15.5	17.9	15.1	12.6	13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	*Bold figures are*		Avg Ann'l P/E Ratio	***15.0***
1.04	1.05	.98	.94	1.06	.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.70	*Value Line*		Relative P/E Ratio	***1.00***
7.2%	6.8%	6.4%	5.9%	5.4%	5.9%	6.2%	5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	*estimates*		Avg Ann'l Div'd Yield	***3.2%***

CAPITAL STRUCTURE as of 3/31/05
Total Debt 1656.0 mill. **Due in 5 Yrs** 335.0 mill.
LT Debt $1618.0 mill. LT Interest $85.0 mill.

(Total interest coverage: 4.5x)
Leases, Uncapitalized Annual rentals $27.0 mill.

Pension Assets-12/04 $279.0 mill. **Oblig.** $340.0 mill.

Pfd Stock None
Common Stock 77,109,918 shs. as of 5/3/05

MARKET CAP: $2.7 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1063.0	1220.2	1287.6	1338.6	1068.6	607.4	1049.3	868.9	983.7	1832.0	***2400***	***2500***	Revenues ($mill) A	***2900***
74.3	75.6	76.6	80.6	52.1	71.1	82.3	103.0	132.4	153.0	***180***	***185***	Net Profit ($mill)	***220***
36.9%	38.6%	37.9%	32.5%	33.1%	34.3%	40.7%	36.0%	35.9%	37.0%	***38.0%***	***38.5%***	Income Tax Rate	***38.5%***
7.0%	6.2%	5.9%	6.0%	4.9%	11.7%	7.8%	11.9%	13.5%	8.4%	***7.5%***	***7.4%***	Net Profit Margin	***7.6%***
47.4%	46.2%	48.7%	47.5%	45.3%	45.9%	61.3%	58.3%	50.3%	54.0%	***52.0%***	***51.0%***	Long-Term Debt Ratio	***46.0%***
47.6%	48.9%	45.9%	47.1%	49.2%	48.3%	38.7%	41.7%	49.7%	46.0%	***48.0%***	***49.0%***	Common Equity Ratio	***54.0%***
1170.3	1201.3	1356.4	1388.4	1345.8	1286.2	1736.3	1704.3	1901.4	3008.0	***3090***	***3175***	Total Capital ($mill)	***3475***
1350.3	1415.4	1496.6	1534.0	1598.9	1637.5	2058.9	2194.2	2352.4	3178.0	***3300***	***3450***	Net Plant ($mill)	***3740***
8.2%	8.0%	7.3%	7.6%	5.7%	7.4%	6.5%	8.1%	8.9%	6.3%	***7.0%***	***7.5%***	Return on Total Cap'l	***7.5%***
12.1%	11.7%	11.0%	11.1%	7.1%	10.2%	12.3%	14.5%	14.0%	11.0%	***12.0%***	***12.0%***	Return on Shr. Equity	***11.5%***
12.5%	12.1%	11.3%	12.3%	7.9%	11.5%	12.3%	14.5%	14.0%	11.0%	***12.0%***	***12.0%***	Return on Com Equity	***11.5%***
4.6%	3.8%	3.2%	4.4%	NMF	3.2%	4.2%	7.0%	6.6%	5.6%	***5.5%***	***5.5%***	Retained to Com Eq	***6.0%***
66%	71%	74%	64%	101%	72%	65%	52%	53%	49%	***54%***	***53%***	All Div'ds to Net Prof	***48%***

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	16.5	49.0	24.0
Other	730.8	1408.0	1155.0
Current Assets	747.3	1457.0	1179.0
Accts Payable	73.7	207.0	648.0
Debt Due	77.0	334.0	38.0
Other	903.7	936.0	528.0
Current Liab.	1054.4	1477.0	1214.0
Fix. Chg. Cov.	357%	510%	440%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	-2.0%	-3.5%	*12.5%*
"Cash Flow"	4.0%	6.5%	*5.5%*
Earnings	6.0%	11.0%	*5.0%*
Dividends	0.5%	0.5%	*3.5%*
Book Value	4.5%	6.0%	*8.0%*

Fiscal Year Begins	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Fiscal Year
2002	173.4	255.1	190.7	249.7	868.9
2003	352.5	186.6	166.3	278.3	983.7
2004	651.0	294.0	262.0	625.0	1832.0
2005	912.0	***385***	***370***	***733***	***2400***
2006	***955***	***400***	***385***	***760***	***2500***

Fiscal Year Begins	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Fiscal Year
2002	.89	.21	.17	.55	1.82
2003	.98	.29	.27	.54	2.08
2004	1.00	.33	.31	.64	2.28
2005	1.14	***.31***	***.29***	***.56***	***2.30***
2006	***1.15***	***.33***	***.31***	***.61***	***2.40***

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.27	.27	.27	.27	1.08
2002	.27	.27	.27	.27	1.08
2003	.27	.28	.28	.28	1.11
2004	.28	.29	.29	.29	1.15
2005	.31	.31			

BUSINESS: AGL Resources, Inc. is a public utility holding company. Its distribution subsidiaries are Atlanta Gas Light, Chattanooga Gas, and Virginia Natural Gas. The utilities have around 2.2 million customers in Georgia, primarily Atlanta, Virginia, and in southern Tennessee. Also engaged in nonregulated natural gas marketing and other, allied services. Also wholesales and retails propane. Nonregulated subsidiaries: Georgia Natural Gas Services markets natural gas at retail. Acquired Virginia Natural Gas, 10/00. Sold Utilipro, 3/01. Off./dir. own less than 1.0% of common stock (3/05 Proxy). President & CEO: Paula Rosput Reynolds. Incorporated: Georgia. Address: 10 Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources first-quarter earnings rose substantially. The March-period results were driven by additional earnings from NUI Corporation and Jefferson Island (about $38 million EBIT), both of which were acquired in the fourth quarter of 2004. These transactions were also responsible for most of the $10 million increase in AGL's interest expense, as the company assumed a substantial amount of debt from these purchases. Looking to the future, AGL has renewed a number of expiring Jefferson contracts with pacts that have staggered expiration dates over the 2006–2010 period. This should provide a fairly consistent revenue stream.

Regulatory matters at Atlanta Gas Light will play an important role in AGL's earnings outlook. The company had filed for a $26 million rate increase, but suffered an adverse ruling from the Georgia Public Service Commission. Its allowable return on equity was reduced from 11% to 10.375%, which is projected to reduce revenues by as much as $25 million. Even so, we are maintaining our earnings estimate of $2.30 a share for 2005, as the company has filed for, and received, a rehearing on the matter. This regulatory issue should be resolved quickly, but we may need to revisit our earnings estimates upon a final ruling.

Sequent Energy, a subsidiary of AGL is expanding. Daily sales have risen nearly 10% over the prior year, from 2.1 Bcf per day to 2.3 Bcf per day. The company would like to boost this volume to around 2.5 Bcf per day, partly by expanding its presence in the Midwest. Although this segment experienced year-over-year losses in the March quarter, that was due to accounting timing differences, which should adjust over time. We look for further expansion at Sequent, as well as AGL's other nonregulated units, which provided 4% of 2004's earnings.

This good-quality stock may appeal to conservative investors. The dividend yield is respectable at 3.5%, which is slightly below that of the average gas distribution stock. However, due to this stock's 35% run-up in price over the past 12 months, it currently offers below-average total-return potential over the pull to 2008–2010.

Evan I. Blatter *June 17, 2005*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, d$0.83; '99, $0.39; '00, $0.13; '01, $0.13; '03, d$0.07. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept, and Dec. ■ Div'd reinvest. plan available.
(D) Includes intangibles. In 2004: $354 million, $4.62/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	45
Earnings Predictability	65

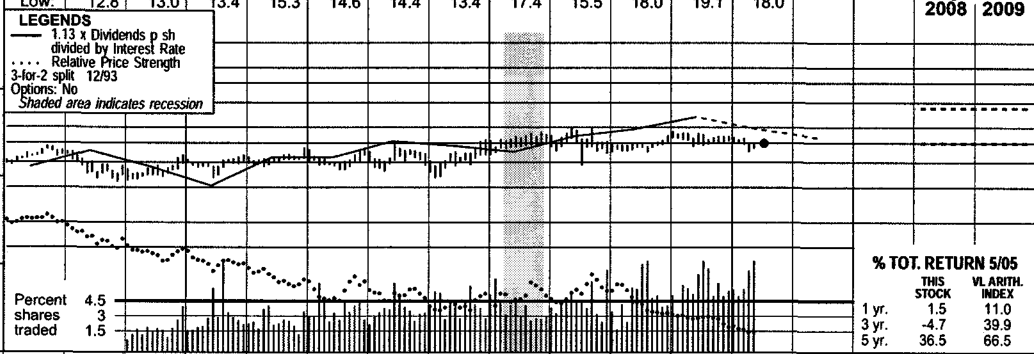
CASCADE NAT'L GAS NYSE-CGC

RECENT PRICE	19.96	P/E RATIO	18.8 (Trailing: 21.5 / Median: 18.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	4.8%	VALUE LINE

TIMELINESS 5 Lowered 11/26/04
SAFETY 3 New 7/27/90
TECHNICAL 3 Raised 5/13/05
BETA .75 (1.00 = Market)

High:	18.1	17.5	17.5	19.0	18.7	19.8	20.9	22.8	24.2	22.0	23.0	21.5
Low:	12.8	13.0	13.4	15.3	14.6	14.4	13.4	17.4	15.5	18.0	19.1	18.0

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	14%
Low	20	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	1	0	0	1	1	0	1
Options	0	0	0	0	0	0	0	2	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	44	33	37
to Sell	30	34	40
Hld's(000)	4631	4676	4743

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	1.5	11.0
3 yr.	-4.7	39.9
5 yr.	36.5	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.87	24.45	23.27	20.03	21.88	21.59	19.98	11.84	17.85	17.17	18.89	21.90	30.40	29.06	27.20	28.23	*27.90*	*29.20*	Revenues per sh A	*40.00*
2.47	2.36	2.29	1.66	2.04	1.71	2.07	1.22	1.92	2.06	2.40	2.60	2.72	2.48	2.25	2.63	*2.50*	*3.00*	"Cash Flow" per sh	*4.60*
1.29	1.26	1.14	.63	1.05	.60	.80	.39	.93	.84	1.24	1.39	1.47	1.13	.87	1.19	*.95*	*1.25*	Earnings per sh AB	*1.60*
.85	.87	.90	.93	.94	.96	.96	.72	.96	.96	.96	.96	.96	.96	.96	.96	*.96*	*.96*	Div'ds Decl'd per sh C■	*.98*
1.99	2.50	2.97	4.64	3.85	3.06	4.12	2.42	2.66	2.32	1.81	1.65	2.16	1.91	2.56	3.50	*2.90*	*3.20*	Cap'l Spending per sh	*4.40*
7.96	8.33	8.63	9.09	9.96	9.81	9.76	10.09	10.16	10.07	10.36	10.79	11.01	10.34	10.11	10.52	*12.45*	*13.60*	Book Value per sh D	*15.30*
6.49	6.56	6.63	7.61	8.57	8.91	9.14	10.79	10.97	11.05	11.05	11.05	11.05	11.05	11.13	11.27	*11.30*	*11.30*	Common Shs Outst'g E	*12.00*
8.6	8.9	12.2	23.7	16.6	25.7	18.2	40.0	17.6	19.4	13.7	11.7	13.4	18.2	22.0	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
.65	.66	.78	1.44	.98	1.69	1.22	2.51	1.01	1.01	.78	.76	.69	.99	1.25	.92	*Value Line*		Relative P/E Ratio	*1.05*
7.7%	7.8%	6.4%	6.2%	5.4%	6.2%	6.6%	4.6%	5.9%	5.9%	5.7%	5.9%	4.9%	4.7%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*
						182.7	127.7	195.8	189.7	208.6	241.9	335.8	321.0	302.8	318.1	*315*	*330*	Revenues ($mill) A	*480*
						7.7	4.2	10.6	9.8	14.2	15.4	16.2	12.5	9.7	13.3	*10.5*	*14.0*	Net Profit ($mill)	*20.0*
						36.8%	34.8%	37.1%	37.4%	36.5%	37.1%	35.0%	34.9%	34.2%	36.2%	*36.5%*	*36.5%*	Income Tax Rate	*36.5%*
						4.2%	3.3%	5.4%	5.2%	6.8%	6.4%	4.8%	3.9%	3.2%	4.2%	*3.3%*	*4.2%*	Net Profit Margin	*4.2%*
						51.4%	46.8%	50.6%	48.4%	50.9%	51.2%	50.7%	59.1%	55.9%	52.1%	*53.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
						45.0%	50.0%	46.5%	48.7%	46.6%	48.8%	49.3%	40.9%	44.1%	47.9%	*47.0%*	*48.0%*	Common Equity Ratio	*49.0%*
						198.5	217.8	239.4	228.5	245.6	244.2	246.6	279.1	255.5	247.4	*300*	*320*	Total Capital ($mill)	*375*
						239.1	255.7	265.2	276.6	282.3	284.8	294.2	299.6	312.3	334.6	*350*	*375*	Net Plant ($mill)	*475*
						5.9%	3.4%	6.2%	6.1%	7.5%	8.1%	8.5%	6.4%	6.0%	7.7%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
						8.0%	3.6%	9.0%	8.3%	11.7%	12.9%	13.3%	10.9%	8.6%	11.2%	*7.5%*	*9.0%*	Return on Shr. Equity	*11.0%*
						8.1%	3.5%	9.1%	8.3%	12.0%	12.9%	13.3%	10.9%	8.6%	11.2%	*7.5%*	*9.0%*	Return on Com Equity	*11.0%*
						NMF	NMF	.7%	NMF	2.7%	4.0%	4.6%	1.7%	NMF	2.1%	*NMF*	*2.0%*	Retained to Com Eq	*4.5%*
						106%	NMF	93%	108%	78%	69%	65%	85%	110%	81%	*103%*	*77%*	All Div'ds to Net Prof	*59%*

CAPITAL STRUCTURE as of 3/31/05

Total Debt $177.4 mill. **Due In 5 Yrs** $55.0 mill.
LT Debt $158.9 mill. **LT Interest** $10.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.7x)

Pension Assets-9/04 $51.3 mill. **Oblig.** $65.5 mill.

Pfd Stock None

Common Stock 11,359,612 shs.
as of 4/29/05
MARKET CAP: $225 million (Small Cap)

CURRENT POSITION A ($MILL.)	2003	2004	3/31/05
Cash Assets	7.5	.5	6.1
Other	33.1	65.9	87.1
Current Assets	40.6	66.4	93.2
Accts Payable	10.5	12.9	22.9
Debt Due	25.8	47.5	18.5
Other	19.7	38.6	51.6
Current Liab.	56.0	99.0	93.0
Fix. Chg. Cov.	213%	269%	260%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	3.0%	9.5%	*6.0%*
"Cash Flow"	3.0%	3.0%	*11.0%*
Earnings	3.5%	1.0%	*7.0%*
Dividends	--	--	*.5%*
Book Value	.5%	--	*7.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	102.8	122.3	56.8	39.1	321.0
2003	100.5	109.3	53.8	39.2	302.8
2004	104.9	119.4	52.1	41.7	318.1
2005	104.6	117.7	*52.0*	*40.7*	*315*
2006	*105*	*125*	*55.0*	*45.0*	*330*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.56	.86	d.06	d.23	1.13
2003	.60	.67	d.18	d.22	.87
2004	.72	.79	d.05	d.26	1.19
2005	.59	.65	*d.06*	*d.23*	*.95*
2006	*.70*	*.80*	*d.07*	*d.18*	*1.25*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.24	.24	.24	.24	.96
2002	.24	.24	.24	.24	.96
2003	.24	.24	.24	.24	.96
2004	.24	.24	.24	.24	.96
2005	.24	.24			

BUSINESS: Cascade Natural Gas Corporation distributes natural gas to around 225,000 customers in Washington and Oregon. In 2004, total throughput was 113.4 billion cu. ft. Core customers: residential, commercial, firm industrial, interruptible (69% of oper. margin, 23% of gas deliveries); non-core: industrial, transportation service (31%, 77%). Serves pulp & paper, plywood, chem. fertilizers, oil refining, & food process. inds. Main connecting pipeline: Northwest Pipeline Corp. '04 deprec. rate: 6.5%. Est'd plant age: 12 yrs. Has around 430 employees. Officers and directors own 1.7% of com. (12/04 proxy). President and Chief Executive Officer: David W. Stevens. Inc.: WA. Address: 222 Fairview Ave. North, Seattle, WA 98109. Tel.: 206-624-3900. Internet: www.cngc.com.

Cascade Natural Gas' earnings per share in fiscal 2005 (ends September 30th) are running substantially behind last year's. Demand from residential and commercial customers is being constrained by warmer temperatures and the effect of conservation efforts spurred by higher natural gas prices. To make matters worse, revenues from the gas management services unit are on the decline, reflecting the loss of some customers to energy marketers (a segment that has re-emerged in the wake of the Enron debacle). But the company's results are benefiting from expansion in the customer base and cost-containment initiatives. Nonetheless, it appears that the aforementioned negative factors will cause share net to plunge roughly 20%, to $0.95, in fiscal 2005. The bottom line stands to bounce back next year, though, assuming, of course, that operating margins recover. That would improve dividend coverage.

The company looks positioned to post decent results out to the end of this decade. Thanks to a generally favorable economic environment, the current pace of new home and commercial construction across Washington and Oregon is steady (resulting in healthy growth in Cascade's annual account hookups). We believe that these positive trends will continue. Moreover, good potential exists for new customers to be gained via conversions to natural gas from electricity or other fuel sources, given natural gas' environmental advantages and assuming that future prices moderate a bit from current levels. Too, management is considering a rate mechanism that would reduce earnings sensitivity to fluctuations in temperatures. (Regulators must approve the measure, however.) Finally, future earnings ought to be helped nicely by a project aimed at diminishing the need for meter readers to manually access customer properties. That said, the bottom line may advance between 8% and 10% annually over the 2008-2010 timeframe.

The stock of Cascade, though untimely, offers an appealing dividend yield. But additional hikes in the payout will likely be slow in coming, as cash flows are used to accommodate the company's expanding customer base.

Frederick L. Harris, III — *June 17, 2005*

(A) Cal. yr. thru. 12/95. Changed to 9/30 fiscal yr. in '96. (B) Primary egs. thru. '97, then diluted. Excl. nonrec. gains (losses): '91, 19¢; '93, 3¢; '96, (11¢); '98, (2¢); '99, (1¢); '01, 9¢; '02, (16¢); '03, (5¢). '04 egs. don't add to total due to rounding. Next egs. rpt. due late July. (C) Dividends historically paid in the middle of Feb., May, Aug., Nov. ■Div'd reinvest. plan avail. (D) Incl. deferred charges. In '04: $21.4 mill., $1.90/sh. (E) In mill., adj. for stk. split.

Company's Financial Strength	B+
Stock's Price Stability	85
Price Growth Persistence	50
Earnings Predictability	70

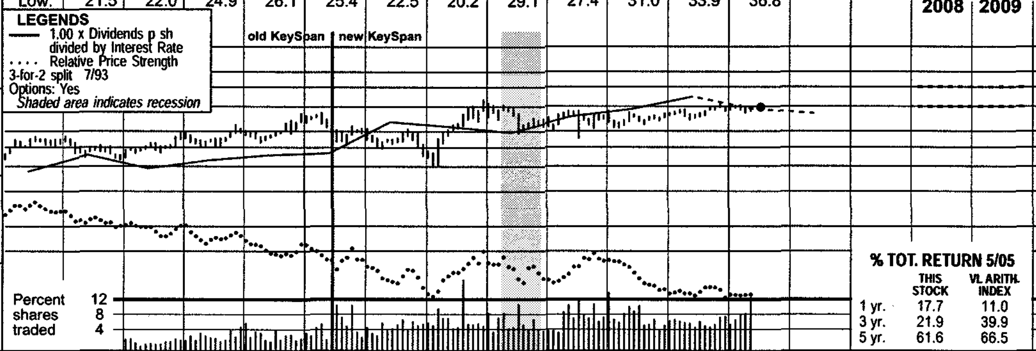
KEYSPAN CORP. NYSE-KSE

RECENT PRICE 39.72 | P/E RATIO 16.6 (Trailing: 10.7 Median: 14.0) | RELATIVE P/E RATIO 0.90 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 4 Lowered 12/10/04
SAFETY 2 Lowered 3/26/99
TECHNICAL 4 Lowered 5/6/05
BETA .80 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	28.6	29.6	32.6	37.1	37.6	31.3	43.6	41.9	38.2	38.1	41.5	40.9
Low:	21.5	22.0	24.9	26.1	25.4	22.5	20.2	29.1	27.4	31.0	33.9	36.8

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+25%)	10%
Low	40	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	4
to Sell	0	0	0	0	0	0	0	0	4

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	135	149	138
to Sell	133	120	135
Hld's(000)	78174	79838	81446

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	17.7	11.0
3 yr.	21.9	39.9
5 yr.	61.6	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
26.71	26.64	23.43	24.74	25.99	28.13	24.93	28.72	29.12	13.20	22.07	37.56	47.57	41.92	43.31	41.35	*40.75*	*43.25*	Revenues per sh	*54.25*
2.64	2.62	2.38	3.03	3.04	3.29	3.35	3.54	4.27	.45	3.57	4.51	5.72	6.36	6.22	7.22	*5.00*	*5.30*	"Cash Flow" per sh	*6.50*
1.68	1.62	1.45	1.35	1.73	1.85	1.90	1.96	2.12	d1.34	1.62	2.10	1.72	2.75	2.62	3.78	*2.40*	*2.60*	Earnings per sh B	*3.25*
1.19	1.23	1.27	1.29	1.32	1.35	1.39	1.42	1.46	1.50	1.78	1.78	1.78	1.78	1.78	1.79	*1.83*	*1.85*	Div'ds Decl'd per sh C ■	*2.00*
4.30	3.51	3.44	3.95	4.37	4.15	4.36	6.04	5.60	5.19	5.42	4.64	7.60	7.96	6.34	4.89	*5.40*	*5.50*	Cap'l Spending per sh	*7.00*
13.36	13.68	14.37	14.55	15.54	16.27	16.94	18.17	19.09	23.18	20.28	20.65	20.73	20.67	22.94	24.22	*26.75*	*27.65*	Book Value per sh D	*30.25*
36.29	37.30	42.28	43.45	46.38	47.59	48.79	49.86	50.77	130.42	133.87	136.36	139.43	142.42	159.66	160.82	*170.00*	*170.00*	Common Shs Outst'g E	*166.00*
10.1	11.9	13.1	15.1	14.3	13.7	12.7	13.7	13.8	--	16.8	14.8	20.8	12.7	13.1	9.90	*Bold figures are*		Avg Ann'l P/E Ratio	*13.5*
.76	.88	.84	.92	.84	.90	.85	.86	.80	--	.96	.96	1.07	.69	.75	.53	*Value*	*Line*	Relative P/E Ratio	*.90*
7.0%	6.4%	6.7%	6.4%	5.3%	5.3%	5.8%	5.3%	5.0%	4.8%	6.5%	5.7%	5.0%	5.1%	5.2%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $5.35 bill. **Due in 5 Yrs** $2.5 bill.
LT Debt $4.42 bill. **LT Interest** $330.0 mill.
(total interest coverage: 3.8x)

Pension Assets-12/04 $1.9 bill. **Oblig.** $2.3 bill.

Pfd Stock $19.7 mill. **Pfd Div'd** $1.4 mill.

Common Stock 160,818,298 shs.

MARKET CAP: $6.4 billion (Large Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1216.3	1432.0	1478.2	1721.9	2954.6	5121.5	6633.1	5970.7	6915.2	6650.5	*6925*	*7325*	Revenues ($mill) A	*9000*
91.8	97.2	106.1	d166.9	258.6	300.8	243.7	397.4	424.2	614.7	*415*	*450*	Net Profit ($mill)	*535*
32.0%	28.9%	35.0%	--	34.5%	41.8%	46.4%	36.2%	39.5%	34.6%	*38.0%*	*38.0%*	Income Tax Rate	*39.0%*
7.6%	6.8%	7.2%	NMF	8.8%	5.9%	3.7%	6.7%	6.1%	9.2%	*6.0%*	*6.1%*	Net Profit Margin	*5.9%*
46.4%	43.8%	43.5%	31.8%	37.5%	59.6%	61.2%	63.3%	60.0%	53.0%	*48.0%*	*48.0%*	Long-Term Debt Ratio	*49.5%*
53.2%	55.8%	56.5%	59.4%	60.6%	39.2%	37.7%	35.7%	39.1%	46.7%	*51.5%*	*51.5%*	Common Equity Ratio	*50.0%*
1553.8	1624.4	1714.1	5089.9	4482.1	7175.0	7672.3	8252.5	9356.9	8333.1	*8850*	*9100*	Total Capital ($mill)	*10050*
1512.6	1698.1	1810.6	3778.3	4240.0	6358.3	6605.9	7217.6	8894.3	7067.9	*7300*	*7700*	Net Plant ($mill)	*9000*
7.5%	7.4%	7.3%	NMF	7.1%	5.3%	4.5%	6.2%	5.8%	9.1%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
11.0%	10.7%	10.9%	NMF	9.2%	10.4%	8.2%	13.1%	11.3%	15.7%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.5%*
11.1%	10.7%	10.9%	NMF	8.2%	10.0%	8.2%	13.3%	11.4%	15.6%	*9.0%*	*9.5%*	Return on Com Equity	*10.5%*
2.9%	2.9%	3.3%	NMF	NMF	1.4%	NMF	4.8%	3.9%	8.3%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
74%	73%	70%	NMF	110%	86%	103%	65%	66%	47%	*75%*	*71%*	All Div'ds to Net Prof	*64%*

CURRENT POSITION ($MILL.)	2002	2003	12/31/04
Cash Assets	170.6	205.8	922.0
Other	2045.9	2181.1	2156.6
Current Assets	2216.5	2386.9	3078.6
Accts Payable	1061.6	1141.6	906.7
Debt Due	927.1	483.4	928.3
Other	231.5	223.8	447.3
Current Liab.	2220.2	1848.8	2282.3
Fix. Chg. Cov.	289%	315%	257%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.0%	13.5%	3.0%
"Cash Flow"	8.0%	17.0%	-0.5%
Earnings	4.5%	21.0%	1.0%
Dividends	3.0%	4.0%	2.0%
Book Value	4.0%	1.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1871.6	1216.1	1079.8	1803.2	5970.7
2003	2512.5	1408.2	1131.8	1862.7	6915.2
2004	2595.6	1365.8	1050.4	1638.7	6650.5
2005	2480.5	*1400*	*1050*	*1994.5*	*6925*
2006	*2650*	*1425*	*1150*	*2100*	*7325*

Cal-endar	EARNINGS PER SHARE A B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.51	.20	.02	1.02	2.75
2003	1.53	d.05	.07	1.07	2.62
2004	1.53	.28	d.73	1.63	2.71
2005	1.45	*.10*	*Nil*	*.85*	*2.40*
2006	*1.30*	*.05*	*Nil*	*1.25*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID A C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.445	.445	.445	.445	1.78
2002	.445	.445	.445	.445	1.78
2003	.445	.445	.445	.445	1.78
2004	.445	.445	.445	.445	1.78
2005	.455	.455			

BUSINESS: KeySpan Corp. is a holding company created 5/98, via the merger of KeySpan Energy (formerly Brooklyn Union) and Long Island Lighting. Acq. Eastern Enterprises 11/00, making KeySpan the largest gas distributor in the Northeast, serving most of New York City and nearby Long Island, and New England. Has 2.5 mill. gas meters in one-family homes and apartments. Also generates electricity and operates transmission/distr. sys. by contract with L.I. Power Author. Parent sold its 23.5% stake in Houston Explor. 11/24/04; Owns 20% of Iroquois Pipeline. Non-regulated subs. market gas supplies, sell ind'l energy mgmt. svcs. Has 9,950 empls. Chrmn.: R.B. Catell. Inc.: NY. Address: 1 MetroTech Center, Brooklyn, NY 11201. Tel.: 718-403-1000. Web:www.keyspanenergy.com.

KeySpan is giving itself a quality makeover. Since 1998, when Brooklyn Union Gas and Long Island Lighting merged to form KeySpan Corp., the new parent set out to bring more kindred businesses into the fold. Early on, it acquired a major New England gas utility, making KeySpan the Northeast's largest regulated gas distributor. Other big investments included new power generation facilities, a majority stake in a Texas gas producer, and the purchase of several mechanical contractors doing energy-related services. But the effort of buying into new markets encountered some damaging financial pitfalls. Too, given its spreading base of nonregulated assets, KeySpan had overleveraged itself with senior capital, leaving a thin margin of safety for the dividend. Last year, though, management carried out a remedial plan, taking leave of shareholder-risk ventures. The outcome: a more comfortable financial profile, which allowed KeySpan to increase the dividend for the first time since the new company was formed.

While not a performance stock, KeySpan seems to be a secure holding for income. The recent conversion of $460 million of debt into common dilutes share earnings a little, but it leaves KeySpan with a balance sheet that's appropriately leveraged for a largely regulated, capital-intensive company. Though regulation leaves little latitude for widening the return on equity, revenues and profits from gas distribution and power generation should grow with the Northeast regional economy, with construction activity helping to expand the customer base. KeySpan trades at a moderate yield premium relative to other good-quality gas-utility stocks. The premium suggests investor doubt that the dividend has room to grow. Our take, at the moment, is that the yearly payout will grow slowly, but fast enough to encourage a little more support for this issue. In terms of business risks, KeySpan, through 2008-2010, is apt to encounter traditional hazards. They include fluctuating electricity prices and regulatory lag in an inflationary economy. KeySpan's recent issuance of $307 million of 30-year notes at 5.8% should help a little to ease the effect of lengthy oversight reviews.

Gerald Holtzman *June 17, 2005*

(A) Data for former KeySpan Energy through '97 (years end 9/30); new KeySpan Corp. from '98 on a calendar-year basis.(B) Diluted shs. Excl. nonrecur. gains (charges): '90, ($0.19); '96, $0.52; '97, $0.16; '03, ($0.23); '04, $0.53. Excl. gain (loss) discont. ops.: '00, ($0.02); '01, ($0.14); '02, ($0.14); '03, $0.01; '04, $0.94. Next egs. report due late July. (C) Dividends historically paid in February, May, August, and November. ■ Div'd reinvestment plan available. (D) Includes deferred charges. At 12/31/04: $18.31 /sh. (E) In millions, adjusted for split.

Company's Financial Strength	B++
Stock's Price Stability	95
Price Growth Persistence	50
Earnings Predictability	20

LACLEDE GROUP NYSE-LG

RECENT PRICE **30.05** | P/E RATIO **16.6** (Trailing: 17.1; Median: 15.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.6%** | VALUE LINE

TIMELINESS 5 Lowered 11/5/04
SAFETY 2 Raised 6/20/03
TECHNICAL 4 Lowered 5/27/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	25.6	23.1	24.9	28.6	27.9	27.0	24.8	25.5	25.0	30.0	32.5	32.8
Low:	18.3	18.4	20.0	20.3	22.4	20.0	17.5	21.3	19.0	21.8	26.0	26.9

2008-10 PROJECTIONS

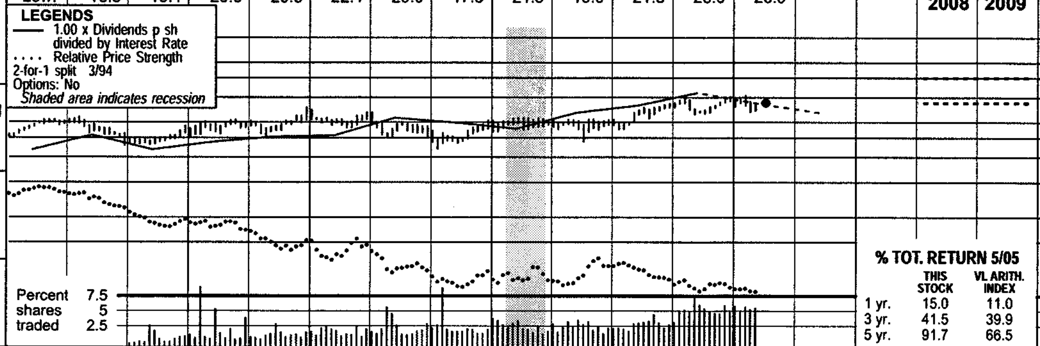
	Price	Gain	Ann'l Total Return
High	40	(+35%)	11%
Low	30	(Nil)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	3	1
to Sell	0	0	0	0	1	0	0	3	1

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	52	45	54
to Sell	35	40	38
Hld's(000)	6476	6396	6440



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	15.0	11.0
3 yr.	41.5	39.9
5 yr.	91.7	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
31.57	30.21	28.10	26.83	32.33	33.43	24.79	31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	*70.70*	*77.65*	Revenues per sh	*103.70*
2.47	2.13	2.37	2.32	2.81	2.65	2.55	3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	*2.90*	*3.25*	"Cash Flow" per sh	*4.20*
1.45	1.08	1.28	1.17	1.61	1.42	1.27	1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	*1.75*	*1.95*	Earnings per sh A B	*2.25*
1.15	1.18	1.20	1.20	1.22	1.22	1.24	1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	*1.37*	*1.38*	Div'ds Decl'd per sh C■	*1.42*
1.82	1.87	2.46	2.87	2.62	2.50	2.63	2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	*2.60*	*2.70*	Cap'l Spending per sh	*3.00*
11.74	11.75	11.83	11.79	12.19	12.44	13.05	13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	*19.60*	*22.35*	Book Value per sh D	*29.65*
15.59	15.59	15.59	15.59	15.59	15.67	17.42	17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	*21.50*	*21.50*	Common Shs Outst'g E	*21.50*
10.3	14.6	12.5	15.8	13.5	16.4	15.5	11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	*15.5*
.78	1.08	.80	.96	.80	1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.82	*estimates*		Relative P/E Ratio	*1.05*
7.7%	7.5%	7.5%	6.5%	5.6%	5.3%	6.3%	5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%			Avg Ann'l Div'd Yield	*3.9%*

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
431.9	544.8	602.8	547.2	491.6	566.1	1002.1	755.2	1050.3	1250.3	*1520*	*1670*	Revenues ($mill) A	*2230*
20.9	32.8	32.5	27.9	26.9	26.0	30.5	22.4	34.6	36.1	*37.5*	*42.0*	Net Profit ($mill)	*50.0*
32.1%	35.9%	36.1%	35.6%	35.5%	35.2%	32.7%	35.4%	35.0%	34.8%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.8%	6.0%	5.4%	5.1%	5.5%	4.6%	3.0%	3.0%	3.3%	2.9%	*2.5%*	*2.5%*	Net Profit Margin	*2.2%*
40.2%	42.5%	38.0%	40.9%	41.8%	45.2%	49.5%	47.5%	50.4%	51.6%	*51.0%*	*51.0%*	Long-Term Debt Ratio	*51.0%*
59.3%	57.1%	61.6%	58.6%	57.8%	54.5%	50.2%	52.3%	49.4%	48.3%	*49.0%*	*49.0%*	Common Equity Ratio	*49.0%*
383.5	422.2	406.8	438.0	488.6	519.2	574.1	546.6	605.0	737.4	*860*	*980*	Total Capital ($mill)	*1300*
434.3	452.2	467.6	490.6	519.4	575.4	602.5	594.4	621.2	646.9	*680*	*705*	Net Plant ($mill)	*800*
7.1%	9.4%	9.7%	8.1%	7.1%	6.7%	6.9%	6.0%	7.4%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
9.1%	13.5%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.5%	10.1%	*9.0%*	*9.0%*	Return on Shr. Equity	*8.0%*
9.2%	13.6%	12.9%	10.8%	9.5%	9.1%	10.5%	7.8%	11.6%	10.1%	*9.0%*	*9.0%*	Return on Com Equity	*8.0%*
.4%	4.5%	3.9%	1.8%	1.0%	.2%	1.8%	NMF	3.1%	2.7%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
96%	67%	70%	83%	89%	98%	83%	113%	74%	73%	*78%*	*71%*	All Div'ds to Net Prof	*61%*

CAPITAL STRUCTURE as of 3/31/05
Total Debt $466.7 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $380.4 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 2.9x)

Leases, Uncapitalized Annual rentals $1.6 mill.
Pension Assets-9/04 $259.5 mill. **Oblig.** $252.6 mill.
Pfd Stock $1.1 mill. **Pfd Div'd** $.06 mill.
Common Stock 21,113,155 shs. as of 4/29/05

MARKET CAP: $625 million (Small Cap)

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	7.3	13.9	17.8
Other	280.6	323.7	366.2
Current Assets	287.9	337.6	384.0
Accts Payable	66.0	68.4	128.5
Debt Due	218.2	96.5	86.3
Other	82.1	97.7	89.8
Current Liab.	366.3	262.6	304.6
Fix. Chg. Cov.	295%	279%	280%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	11.0%	*12.5%*
"Cash Flow"	1.0%	-1.0%	*7.0%*
Earnings	1.5%	-.5%	*6.0%*
Dividends	1.0%	.5%	*1.0%*
Book Value	2.5%	1.5%	*11.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	194.6	287.5	147.3	125.8	755.2
2003	280.1	422.2	186.6	161.4	1050.3
2004	332.6	475.0	245.1	197.6	1250.3
2005	442.5	576.5	*276*	*225*	*1520*
2006	*490*	*600*	*305*	*275*	*1670*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.41	1.10	d.05	d.28	1.18
2003	.80	1.14	.11	d.21	1.82
2004	.87	1.12	.19	d.28	1.82
2005	.79	1.06	*.18*	*d.28*	*1.75*
2006	*.85*	*1.15*	*.20*	*d.25*	*1.95*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.335	.335	.335	.335	1.34
2002	.335	.335	.335	.335	1.34
2003	.335	.335	.335	.335	1.34
2004	.335	.34	.34	.34	1.36
2005	.34	.345			

BUSINESS: Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri (population, 2 million), including the city of St. Louis, St. Louis County, and parts of 8 other counties. Has more than 630,000 customers. Purchased SM&P for $43 million (1/02). Therms sold and transported in fiscal '04: 1.12 mill. Revenue mix for regulated operations: residential, 63%; commercial and industrial, 23%; transportation, 2%; other, 12%. Has around 3,440 employees. Officers and directors own approximately 6.0% of common shares (1/05 Proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.lacledegas.com.

In spite of higher revenues, Laclede Group's fiscal 2005 earnings per share have been lower than the year-ago figure. The shortfall partly reflects the dilutive impact of the sale of 1.7 million common shares in 2004. Moreover, Laclede Gas Company, the core unit, is suffering from the net effect of decreased gas volumes (due to unseasonably warm weather last November), plus a rise in operating costs (particularly natural gas and propane gas expense). On the positive side, the performance of Laclede Energy Resources is being boosted by increased margins and higher sales achieved in a favorable market. Also, losses for SM&P Utility Resources are narrowing, thanks to the return of a considerable portion of business from two customers and expansion into new and existing markets. Nevertheless, it appears that consolidated share net will decline moderately, to $1.75, in fiscal 2005. But the bottom line may snap back next year, assuming, of course, better demand and/or lower gas purchase costs.

We expect unexciting results for the company out to decade's end, given that Laclede Gas operates in a mature market. In fact, the customer base is expanding less than 1% annually, which means that internal growth for this operation will be modest, at best. As such, any substantial gains will have to come from the unregulated segments or from acquisitions, which we view as improbable. That said, annual share-net advances may only be in the mid-single-digit range over the 2008-2010 horizon.

Laclede Gas formed a long-term agreement with Cellnet Technology, under which the latter would install and operate an automated meter reading system. This move should eliminate the need for the utility, with nearly 40% of its meters indoors, to gain physical access to the customer properties (thus resulting in cost savings). The project is slated for completion in two years.

The good-quality stock offers an attractive dividend yield. But investors seeking significant growth in the payout are advised to look elsewhere, given that the gas distributor operates in a slow-growth environment. Meanwhile, the stock is ranked 5 (Lowest) for Timeliness.

Frederick L. Harris, III *June 17, 2005*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Next earnings report due late April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Incl. deferred charges. In '04: $206.6 mill., $9.85/sh.
(E) In millions. Adjusted for stock split.
(F) Qtly. egs. may not sum due to change in shares outstanding.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	65

NICOR, INC. NYSE-GAS

RECENT PRICE	39.67	P/E RATIO	18.9 (Trailing: 17.7 Median: 14.0)	RELATIVE P/E RATIO	1.03	DIV'D YLD	4.7%	VALUE LINE

TIMELINESS 4 Lowered 5/13/05
SAFETY 3 Lowered 6/17/05
TECHNICAL 4 Lowered 6/10/05
BETA 1.10 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:		29.3	28.5	37.1	42.9	44.4	42.9	43.9	42.4	49.0	39.3	39.7	40.6
Low:		21.9	21.8	25.4	30.0	37.1	31.2	29.4	34.0	17.3	23.7	32.0	35.5

Target Price Range 2008 | 2009 | 2010

2008-10 PROJECTIONS

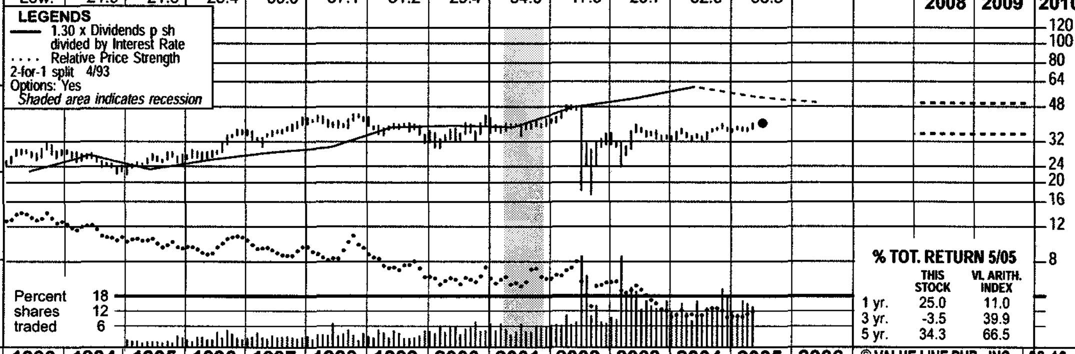
	Price	Gain	Ann'l Total Return
High	50	(+25%)	10%
Low	35	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	1	0	0	1	0	0	1	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	86	109	96
to Sell	85	66	95
Hld's(000)	27339	27979	27493



% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	25.0	11.0
3 yr.	-3.5	39.9
5 yr.	34.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
27.37	26.52	26.46	28.90	31.02	31.23	29.42	37.39	41.33	30.84	34.45	50.52	57.30	43.11	60.46	62.12	66.75	67.85	Revenues per sh	68.55
3.79	3.86	3.92	4.14	3.80	4.11	4.19	4.97	5.29	5.21	5.59	6.16	6.41	6.03	5.37	6.00	6.10	6.35	"Cash Flow" per sh	6.95
1.99	1.93	1.86	1.92	1.97	2.07	1.96	2.42	2.55	2.31	2.57	2.94	3.01	2.88	2.11	2.22	2.10	2.25	Earnings per sh A	2.55
1.00	1.06	1.12	1.18	1.22	1.25	1.28	1.32	1.40	1.48	1.54	1.66	1.76	1.84	1.86	1.86	1.86	1.86	Div'ds Decl'd per sh B ■	2.02
2.53	3.00	3.65	3.12	2.62	3.34	3.12	2.42	2.34	2.87	3.28	3.48	4.18	4.37	4.12	4.32	5.10	4.50	Cap'l Spending per sh	4.50
11.05	11.67	12.28	12.76	13.05	13.26	13.67	14.74	15.43	15.97	16.80	15.56	16.39	16.55	17.13	16.99	17.30	17.75	Book Value per sh	19.10
59.24	57.93	57.30	55.77	53.96	51.54	50.30	49.49	48.22	47.51	46.89	45.49	44.40	44.01	44.04	44.10	44.20	44.20	Common Shs Outst'g C	44.50
9.2	10.7	11.5	11.6	14.1	12.5	13.1	12.5	14.2	17.6	14.6	11.9	12.8	13.1	15.8	15.9	Bold figures are		Avg Ann'l P/E Ratio	16.0
.70	.79	.73	.70	.83	.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.85	Value Line		Relative P/E Ratio	1.05
5.5%	5.1%	5.2%	5.3%	4.4%	4.8%	5.0%	4.4%	3.9%	3.6%	4.1%	4.7%	4.6%	4.9%	5.6%	5.3%	estimates		Avg Ann'l Div'd Yield	5.1%

CAPITAL STRUCTURE as of 3/31/05
Total Debt $530.0 mill. Due in 5 Yrs $665.0 mill.
LT Debt $495.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 4.5x)

No Defined Benefit Pension Plan

Pfd Stock $1.6 mill. **Pfd Div'd** Nil

Common Stock 44,136,171 shares
as of 4/29/05

MARKET CAP: $1.6 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1480.1	1850.7	1992.6	1465.1	1615.2	2298.1	2544.1	1897.4	2662.7	2739.7	2950	3000	Revenues ($mill)	3050
99.8	121.2	124.3	111.1	121.9	136.4	136.3	128.0	93.1	98.1	95.0	100	Net Profit ($mill)	115
35.3%	35.8%	35.0%	34.4%	34.7%	34.8%	33.5%	31.0%	35.2%	31.8%	33.0%	33.0%	Income Tax Rate	33.0%
6.7%	6.5%	6.2%	7.6%	7.5%	5.9%	5.4%	6.7%	3.5%	3.6%	3.2%	3.3%	Net Profit Margin	3.8%
40.2%	41.3%	42.3%	42.1%	35.5%	32.7%	37.8%	35.1%	39.6%	39.8%	39.5%	38.5%	Long-Term Debt Ratio	37.0%
59.0%	58.1%	57.2%	57.4%	64.0%	66.7%	61.7%	64.5%	60.3%	60.1%	60.5%	61.5%	Common Equity Ratio	63.0%
1165.2	1255.1	1300.6	1322.6	1230.1	1061.2	1180.1	1128.9	1251.5	1246.0	1260	1280	Total Capital ($mill)	1345
1779.3	1771.9	1735.8	1731.8	1735.2	1729.6	1768.6	1796.8	2484.2	2549.8	2630	2700	Net Plant ($mill)	2930
10.1%	11.1%	11.1%	9.9%	10.9%	13.7%	12.3%	12.2%	8.3%	8.8%	9.0%	9.5%	Return on Total Cap'l	10.0%
14.3%	16.4%	16.6%	14.5%	15.4%	19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	12.5%	Return on Shr. Equity	13.5%
14.4%	16.6%	16.7%	14.6%	15.4%	19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	12.5%	Return on Com Equity	13.5%
5.0%	7.6%	7.6%	5.4%	6.2%	8.5%	7.9%	6.5%	1.5%	2.1%	1.7%	2.3%	Retained to Com Eq	2.9%
65%	54%	55%	63%	60%	56%	58%	63%	88%	84%	86%	82%	All Div'ds to Net Prof	78%

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	83.2	83.2	93.5
Other	832.7	937.7	784.4
Current Assets	915.9	1020.9	877.9
Accts Payable	385.4	502.9	369.5
Debt Due	575.0	490.2	34.6
Other	108.3	178.3	585.3
Current Liab.	1068.7	1171.4	989.4
Fix. Chg. Cov.	437%	428%	NMF

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.0%	9.0%	3.5%
"Cash Flow"	3.5%	1.5%	3.0%
Earnings	2.0%	-0.5%	1.0%
Dividends	4.5%	4.5%	1.5%
Book Value	2.5%	1.0%	2.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	551.1	391.8	249.8	704.7	1897.4
2003	1171.3	452.8	294.8	743.8	2662.7
2004	1115.7	429.5	299.9	894.6	2739.7
2005	1179.8	445	315	1010.2	2950
2006	1200	455	320	1025	3000

Cal-endar	EARNINGS PER SHARE A D Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.82	.50	.67	.89	2.88
2003	1.11	.21	.01	.78	2.11
2004	.96	.44	d.26	1.08	2.22
2005	.98	.30	d.10	.92	2.10
2006	1.00	.40	d.15	1.00	2.25

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.415	.44	.44	.44	1.74
2002	.46	.46	.46	.46	1.84
2003	.46	.465	.465	.465	1.86
2004	.465	.465	.465	.465	1.86
2005	.465	.465			

BUSINESS: Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.1 million customers in northern and western Illinois. 2004 gas delivered: 473.2 bcf, incl. 217.7 bcf from transportation. 2004 gas sales (255.5 bcf): residential, 80%; commercial, 17%; industrial, 3%. Principal supplying pipelines: Natural Gas Pipeline, Midwestern Gas, and Northern Natural. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested inland barging, 7/86; contract drilling, 9/86; oil and gas E&P, 6/93. Has about 3,600 employees, 23,700 stkhldrs. Off./dir. own about 1.9% of cmmn. stk. (4/05 proxy). CEO: Russ Strobel. Inc.: IL. Address: 1844 Ferry Road, Naperville, IL 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

Nicor, Inc. will probably post weaker earnings in 2005. Profits should be weighed down by the underperforming gas distribution business, which has incurred higher operating and maintenance expenses. Indeed, such costs have continued to rise over the past couple of years due to a number of factors, such as an increase in labor and benefit-related expenses. Also, the surge in natural gas prices has led the company to raise its bad debt provisions. This negative trend will probably continue through the balance of the year. Our assumptions are largely based on near-term natural gas prices, as well as the greater capital costs necessary to sustain and expand Nicor's service territories.

Rate relief is still pending. Last November, the company made an initial filing with the Illinois Commerce Commission (ICC), requesting an increase in business and residential rates of $83.3 million in an effort to recoup operating costs. In addition, Nicor has proposed to pass on approximately two-thirds of all bad debt expenses to customers. We note that this is the company's first rate filing in nearly 10 years, as it absorbed incremental operating costs in that time. However, it remains uncertain if the company will receive the full amount of relief. A decision is expected to be reached in the fourth quarter.

The long-term earnings picture is less clear. We assume that the ICC will provide Nicor with some financial assistance, contributing to an earnings recovery in the coming year. But our earnings projections are subject to revision once the final order is delivered.

A ramp-up in capital spending may well hamper dividend growth. The company's capital expenditure budget for 2005 is up 20%, to $225 million. Given the larger capital outlays, Nicor should find it more challenging to increase the dividend payout in the foreseeable future. In the last two years, an unusually high percentage of net income was required to support the current dividend rate.

Falling bond yields are supporting untimely Nicor stock. But under current market conditions, the company has not been able to generate sufficient revenue to offset rising operating costs. Limited dividend growth also warrants concern.

Charles W. Noh *June 17, 2005*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '89, 7¢; '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next earnings report due early August. (B) Dividends historically paid early February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions, adjusted for stock split. (D) 2002 quarters do not sum to total due to change in shares outstanding.

Company's Financial Strength	A
Stock's Price Stability	65
Price Growth Persistence	65
Earnings Predictability	80

N.W. NAT'L GAS NYSE-NWN

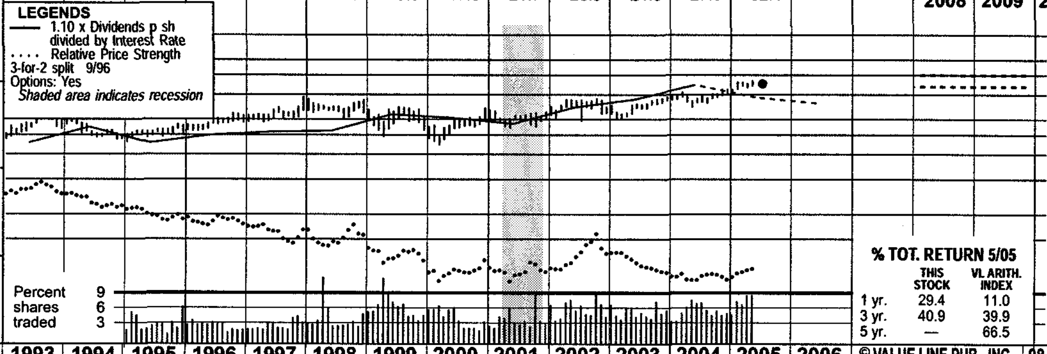
RECENT PRICE 36.30 | P/E RATIO 15.8 (Trailing: 17.7 Median: 14.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 3 Raised 3/11/05
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Lowered 12/24/04
BETA .70 (1.00 = Market)

High:	24.3	22.8	25.9	31.4	30.8	27.9	27.5	26.8	30.7	31.3	34.1	37.8
Low:	18.8	18.3	20.8	23.0	24.3	19.5	17.8	21.7	23.5	24.0	27.5	32.4

Target Price Range 2008 | 2009 | 2010

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+10%)	6%
Low	35	(-5%)	3%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	0
Options	0	2	3	0	3	3	0	4	2
to Sell	0	1	2	0	1	3	0	4	2

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	55	51	58
to Sell	57	50	51
Hld's(000)	12727	12975	12963

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	29.4	11.0
3 yr.	40.9	39.9
5 yr.	—	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.22	17.02	16.74	14.10	18.15	18.30	16.02	16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	*29.20*	*30.55*	Revenues per sh	*35.00*
2.85	3.22	2.57	3.25	3.74	3.50	3.41	3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	*4.50*	*4.70*	"Cash Flow" per sh	*5.50*
1.58	1.62	.67	.74	1.74	1.63	1.61	1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	*2.30*	*2.40*	Earnings per sh A	*2.70*
1.07	1.10	1.13	1.15	1.17	1.17	1.18	1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	*1.33*	*1.36*	Div'ds Decl'd per sh B■	*1.50*
3.36	3.85	3.58	3.73	3.61	4.23	3.02	3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	*5.00*	*5.00*	Cap'l Spending per sh	*5.00*
12.04	12.61	12.23	12.41	13.08	13.63	14.55	15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	*21.45*	*22.50*	Book Value per sh C	*25.60*
17.14	17.41	17.68	19.46	19.77	20.13	22.24	22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	*27.75*	*28.00*	Common Shs Outst'g D	*28.50*
9.8	10.2	28.1	27.0	12.9	13.0	12.9	11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	Bold figures are	Value Line	Avg Ann'l P/E Ratio	*13.5*
.74	.76	1.79	1.64	.76	.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.89	estimates		Relative P/E Ratio	*.90*
6.9%	6.7%	5.9%	5.7%	5.2%	5.5%	5.7%	5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%			Avg Ann'l Div'd Yield	*4.2%*

CAPITAL STRUCTURE as of 12/31/04
Total Debt $601.5 mill. Due in 5 Yrs $160.0 mill.
LT Debt $484.0 mill. LT Interest $33.0 mill.
Incl. $5.6 mill. 7¼% debs. due 3/1/12, each conv. into 50.25 com. shs. at $19.90.
(Total interest coverage: 3.2x)

Pension Assets-12/04 $168.3 mill. **Oblig.** $205.4 mill.

Pfd Stock None

Common Stock 27,546,719 shs.
MARKET CAP $1.0 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
356.3	380.3	361.8	416.7	455.8	532.1	650.3	641.4	611.3	707.6	*810*	*855*	Revenues ($mill)	*1000*
38.1	46.8	43.1	27.3	44.9	47.8	50.2	43.8	46.0	50.6	*63.5*	*67.0*	Net Profit ($mill)	*77.0*
36.8%	36.9%	32.9%	31.0%	35.4%	35.9%	35.4%	34.9%	33.7%	34.4%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
10.7%	12.3%	11.9%	6.6%	9.9%	9.0%	7.7%	6.8%	7.5%	7.1%	*7.8%*	*7.8%*	Net Profit Margin	*7.7%*
43.5%	41.4%	46.0%	45.0%	46.0%	45.1%	43.0%	47.6%	49.7%	46.0%	*45.5%*	*45.0%*	Long-Term Debt Ratio	*46.0%*
50.3%	52.8%	49.0%	50.6%	49.9%	50.9%	53.2%	51.5%	50.3%	54.0%	*54.5%*	*55.0%*	Common Equity Ratio	*54.0%*
643.3	657.4	748.0	815.6	861.5	887.8	880.5	937.3	1006.6	1052.5	*1100*	*1150*	Total Capital ($mill)	*1360*
697.2	745.3	827.5	894.7	895.9	934.0	965.0	995.6	1205.9	1318.4	*1370*	*1430*	Net Plant ($mill)	*1625*
7.7%	8.9%	7.4%	5.0%	6.8%	6.7%	6.9%	5.9%	5.7%	5.9%	*7.0%*	*7.0%*	Return on Total Cap'l	*8.0%*
10.5%	12.1%	10.7%	6.1%	9.7%	9.8%	10.0%	8.9%	9.1%	8.9%	*10.5%*	*10.5%*	Return on Shr. Equity	*10.5%*
10.9%	12.7%	11.0%	6.0%	9.9%	10.0%	10.2%	8.5%	9.0%	8.9%	*10.5%*	*10.5%*	Return on Com Equity	*10.5%*
3.0%	5.0%	3.6%	NMF	2.8%	3.1%	3.5%	1.9%	2.6%	2.7%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
74%	63%	70%	118%	74%	70%	67%	79%	72%	69%	*58%*	*57%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2002	2003	12/31/04
Cash Assets	7.3	4.7	5.2
Other	186.7	194.8	231.9
Current Assets	194.0	199.5	237.1
Accts Payable	74.4	86.0	102.5
Debt Due	89.8	85.2	117.5
Other	40.8	43.2	47.3
Current Liab.	205.0	214.4	267.3
Fx. Chg. Cov.	296%	280%	316%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	8.0%	*6.0%*
"Cash Flow"	1.0%	1.5%	*6.5%*
Earnings	2.5%	3.0%	*7.5%*
Dividends	1.0%	1.0%	*2.5%*
Book Value	4.0%	3.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	278.6	101.9	78.7	182.2	641.4
2003	206.5	117.5	69.5	217.8	611.3
2004	254.5	109.7	81.4	262.0	707.6
2005	308.8	*125*	*90.0*	*286.2*	*810*
2006	*325*	*133*	*97.0*	*300*	*855*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.32	d.13	d.26	.69	1.62
2003	1.01	.17	d.25	.83	1.76
2004	1.24	d.03	d.30	.95	1.86
2005	1.43	*.17*	*d.30*	*1.00*	*2.30*
2006	*1.50*	*.17*	*d.31*	*1.04*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.31	.31	.315	1.25
2002	.315	.315	.315	.315	1.26
2003	.315	.315	.315	.325	1.27
2004	.325	.325	.325	.325	1.30
2005	.325	.325			

BUSINESS: Northwest Natural Gas Co. (doing business as NW Natural) distributes natural gas at retail to 90 communities, 596,000 customers, in Oregon (96% of revs.) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.4 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline sys. to bring gas to market. Owns local underground storage. Rev. breakdown: resident'l & comm'l, 84%; ind., 10%; transport. and other, 6%. Employs 1,291. Has about 10,000 com. shrhldrs. Insiders own about 1% of com. Ch. Exec. Off.: Richard Woolworth. Inc.: OR. Addr.: 220 N.W. 2nd Ave., Portland, OR 97209. Tel.: 503-226-4211. Web: www.nwnatural.com.

Northwest Natural has gained a good measure of investor confidence as an income stock. The returns available from high-quality fixed-income securities serve as Wall Street's benchmark for setting the yields on utility shares. In NW Natural's case, the current yield is moderately below the gas-stock average. That's because the utility's improved earnings promise of late has raised dividend-growth expectations, giving this stock an added prop.

This regulated gas distributor does business in a diversified and growing economy. Customer rolls in the Pacific Northwest are expanding at about 3% a year, thanks to new residential and commercial construction and conversions to gas from alternate fuels and power in older homes. Today, NW Natural has only about 50% of the region's home-heating market, and natural gas still holds an overall economic edge over fuel oil and electricity. So, with adequate gas supplies available from U.S. and Canadian fields, we expect the company to continue building its market share and sustain enough earning power to keep the dividend growing by 2% a year, or better, into 2007.

But there are risks. NW Natural appears to be getting fair treatment from its state regulators. The allowed return on common equity is a bit more than 10%, taking into account today's low borrowing costs. Giving the utility an added advantage, however, is a newly ordered weather normalization tariff that serves to negate the effect of winter temperature extremes. It should permit the utility a smoother upward earnings curve and afford management a more predictable cash flow for financial planning and dividend decisions. The new rate design worked nicely to NW Natural's favor last winter, enabling profits to move higher when thermometer readings were above normal. But looking ahead a year or two, the prospect of rising interest rates presents a potential investment risk, in that NW Natural's request for higher tariffs to cover increased borrowing costs might well require many months of oversight review. And a profit squeeze due to regulatory lag may preclude a dividend hike, with the general rise in bond yields likely putting more downward pressure on this equity's price.

Gerald Holtzman *June 17, 2005*

(A) Diluted earnings per share. Excludes nonrecurring gain: '98, $0.15; '00, $0.11. Next earnings report due late July.
(B) Dividends historically paid in mid-February, mid-May, mid-August, and mid-November.
■ Div'd reinvestment plan available.
(C) Includes intangibles. At 12/31/04: $4.21/sh.
(D) In millions, adjusted for stock split.

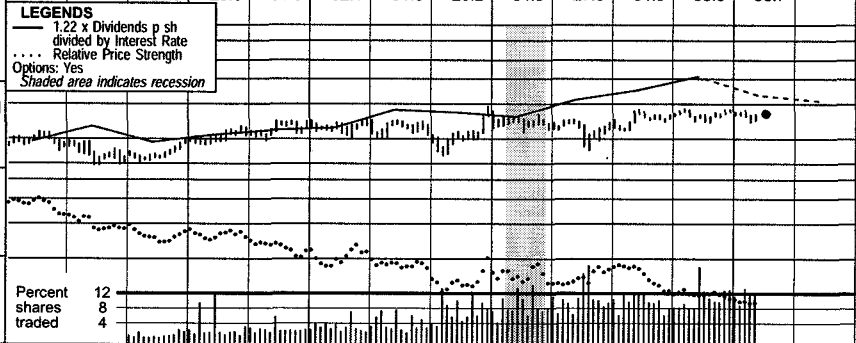
Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	40
Earnings Predictability	65

PEOPLES ENERGY NYSE-PGL

RECENT PRICE **42.98** | P/E RATIO **16.2** (Trailing: 21.6 / Median: 14.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **5.1%** | VALUE LINE

TIMELINESS 5 Lowered 2/4/05
SAFETY 1 Raised 9/29/95
TECHNICAL 3 Lowered 3/4/05
BETA .80 (1.00 = Market)

High:	32.1	32.0	37.4	39.9	40.1	40.3	46.9	44.6	40.4	45.3	46.0	45.1
Low:	23.4	24.3	29.6	31.3	32.1	31.8	26.2	34.3	27.8	34.9	38.5	38.7



Target Price Range

2008	2009	2010

120 / 100 / 80 / 64 / 48 / 32 / 24 / 20 / 16 / 12 / 8

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	13%
Low	50	(+15%)	8%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	2	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	80	98	94
to Sell	72	54	73
Hld's(000)	19912	21183	19746

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	7.1	11.0
3 yr.	25.2	39.9
5 yr.	58.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
36.42	35.63	33.69	31.54	36.09	36.70	29.60	34.29	36.34	32.28	33.66	40.16	64.13	41.81	58.28	59.90	*63.70*	*62.90*	Revenues per sh A	*76.15*
3.92	3.74	3.73	3.67	3.85	3.99	3.68	4.98	4.92	4.44	4.74	5.58	5.84	5.59	5.88	5.32	*5.80*	*6.05*	"Cash Flow" per sh	*7.15*
2.39	2.07	2.05	2.06	2.11	2.13	1.78	2.96	2.81	2.25	2.39	2.71	3.16	2.80	2.87	2.18	*2.60*	*2.70*	Earnings per sh B	*3.20*
1.58	1.65	1.71	1.76	1.78	1.80	1.80	1.82	1.87	1.91	1.95	2.00	2.04	2.07	2.12	2.16	*2.18*	*2.20*	Div'ds Decl'd per sh C ■	*2.32*
4.15	3.15	3.10	3.40	3.77	2.50	2.75	2.45	2.55	4.05	6.45	7.02	7.52	5.66	5.10	5.02	*4.60*	*4.75*	Cap'l Spending per sh	*6.55*
16.20	16.61	16.95	17.72	18.02	18.39	18.38	19.49	20.43	21.03	21.66	22.02	22.76	22.74	23.11	23.06	*23.30*	*24.10*	Book Value per sh D	*29.45*
32.62	32.70	32.76	34.77	34.88	34.87	34.91	34.96	35.07	35.26	35.49	35.30	35.40	35.46	36.69	36.69	*38.00*	*38.00*	Common Shs Outst'g E	*35.00*
7.9	11.2	11.8	13.1	15.0	13.3	14.7	10.7	12.7	16.2	15.5	12.1	12.3	13.3	13.4	19.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.60	.83	.75	.79	.89	.87	.98	.67	.73	.84	.88	.79	.63	.73	.76	1.02	*Value Line*		Relative P/E Ratio	*1.15*
8.4%	7.1%	7.0%	6.5%	5.6%	6.3%	6.9%	5.7%	5.2%	5.2%	5.3%	6.1%	5.2%	5.5%	5.5%	5.2%	*estimates*		Avg Ann'l Div'd Yield	*4.3%*

CAPITAL STRUCTURE as of 3/31/05

Total Debt $895.6 mill. **Due in 5 Yrs** $315.0 mill.

LT Debt $895.6 mill. **LT Interest** $50.0 mill.
(Total interest coverage: 4.7x)

Pension Assets-9/04 $544.9 mill. **Oblig.** $515.8 mill.

Pfd Stock None

Common Stock 38,018,378 shs.
as of 4/29/05
MARKET CAP: $1.6 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
1033.4	1198.7	1274.4	1138.1	1194.4	1417.5	2270.2	1482.5	2138.4	2260.2	*2420*	*2390*	Revenues ($mill) A	*2665*
62.2	103.4	98.4	79.4	84.8	96.1	111.7	99.3	103.9	81.6	*100*	*105*	Net Profit ($mill)	*110*
34.4%	37.6%	36.4%	36.2%	35.9%	34.1%	35.4%	34.2%	36.3%	31.7%	*35.5%*	*35.5%*	Income Tax Rate	*35.5%*
6.0%	8.6%	7.7%	7.0%	7.1%	6.8%	4.9%	6.7%	4.9%	3.6%	*4.1%*	*4.4%*	Net Profit Margin	*4.1%*
49.2%	43.6%	42.4%	41.1%	40.4%	35.1%	44.4%	40.7%	46.7%	50.8%	*50.0%*	*49.5%*	Long-Term Debt Ratio	*46.5%*
50.8%	56.4%	57.6%	58.9%	59.6%	64.9%	55.6%	59.3%	53.3%	49.2%	*50.0%*	*50.5%*	Common Equity Ratio	*53.5%*
1263.6	1208.3	1243.5	1258.0	1290.5	1196.7	1449.8	1360.3	1592.3	1767.5	*1775*	*1805*	Total Capital ($mill)	*1920*
1373.1	1381.1	1402.2	1446.7	1519.8	1645.3	1753.9	1773.9	1838.2	1904.2	*1970*	*2035*	Net Plant ($mill)	*2305*
7.0%	10.3%	9.5%	7.8%	8.0%	9.5%	9.3%	8.4%	8.1%	6.0%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	*11.5%*	*11.5%*	Return on Shr. Equity	*10.5%*
9.7%	15.2%	13.7%	10.7%	11.0%	12.4%	13.9%	12.3%	12.3%	9.4%	*11.5%*	*11.5%*	Return on Com Equity	*10.5%*
NMF	5.9%	4.7%	1.7%	2.1%	3.4%	5.0%	3.3%	3.4%	.2%	*2.0%*	*2.0%*	Retained to Com Eq	*3.0%*
101%	61%	66%	84%	81%	73%	64%	73%	73%	97%	*83%*	*80%*	All Div'ds to Net Prof	*74%*

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	33.0	21.1	100.5
Other	457.1	531.3	715.7
Current Assets	490.1	552.4	816.2
Accts Payable	236.6	144.7	220.8
Debt Due	207.9	55.6	- -
Other	156.1	335.8	510.9
Current Liab.	600.6	536.1	731.7
Fix. Chg. Cov.	259%	304%	388%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.0%	10.0%	*2.5%*
"Cash Flow"	4.5%	4.0%	*2.0%*
Earnings	3.5%	2.0%	*1.0%*
Dividends	1.5%	2.0%	*1.5%*
Book Value	2.5%	2.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	377.5	522.8	347.1	235.1	1482.5
2003	549.2	903.8	398.1	287.3	2138.4
2004	604.9	927.0	401.1	327.1	2260.2
2005	737.4	1026.9	*360*	*295.7*	*2420*
2006	*730*	*1015*	*355*	*290*	*2390*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.87	1.55	.33	.05	2.80
2003	.87	1.77	.22	.04	F 2.87
2004	.85	1.46	.15	d.27	F 2.18
2005	.77	1.37	*.31*	*.15*	*2.60*
2006	*.83*	*1.51*	*.25*	*.11*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.50	.51	.51	.51	2.03
2002	.51	.52	.52	.52	2.07
2003	.53	.53	.53	.53	2.12
2004	.54	.54	.54	.54	2.16
2005	.545	.545			

BUSINESS: Peoples Energy Corporation distributes natural gas via its utility subsidiaries, Peoples Gas Light & Coke Co. (approx. 1,000,000 customers at 9/30/04) and North Shore Gas Co. (150,000), in Chicago and northeastern Illinois. Fiscal 2004 volume: 229 bill. cu. ft.: residential, 51%; commercial, 9%; industrial, 2%; other, 38%. Main supplier is Natural Gas Pipeline Co. of America. Purchased gas costs and revenue taxes accounted for 67% of gas revenues in fiscal '04. Depreciation rate: 3.5%. Est'd plant age: 10 years. Has 2,400 employees, 20,988 shareholders. Directors own 1% of common (1/05 Proxy). Chairman and CEO: Thomas M. Patrick. Inc.: Illinois. Address: 130 East Randolph Drive, Chicago, IL 60601. Telephone: 312-240-4000. Internet: www.pecorp.com.

Peoples Energy continues to struggle with warmer weather. During the second fiscal quarter (year ends September 30th), temperatures in the company's service territory ran 5.3% warmer than normal and almost 4% warmer than last year. This resulted in a $5 million shortfall in operating income, and, consequently, share net of $1.37 was well below our $1.49 estimate. Year-to-date, weather has negatively impacted operating income by $11 million. Peoples will be filing for a weather normalization adjustment with the Illinois Commerce Commission that should ultimately reduce the negative impact of temperature volatility. However, we expect this will be a relatively long process and so no near-term relief is likely. Stronger results in the company's Retail and Power Generation segments were not enough to offset weaker performances in the Gas Distribution unit. What's more,

Production volumes in the Oil and Gas segment dipped again. Overall production in the quarter declined nearly 20% year over year and 6% sequentially. Management once again cited ongoing timing delays with the company's drilling program, in addition to well performance issues, pipeline curtailments, and equipment downtime. Peoples expects volume growth to pick up in the second half of 2005, but we have taken a more conservative standpoint, as we suspect it may take longer than anticipated to get production growth back on track.

We have lowered our earnings estimate for fiscal 2005 by a nickel, to $2.60. This is at the lower end of management's target range. We believe Peoples will not be able to overcome the effects of the warm winter and oil production shortfalls. At this level of earnings, the company's payout ratio stands at over 80%, which is higher than the historical average, and prompts us to wonder whether dividend increases will be slow to come in the future. Noncore operations have not been enough to cover the faltering gas distribution business. That said, we believe the dividend is safe, though we expect management might choose keep any quarterly increases to one-half cent per share, rather than the one-cent gains shareholders were used to in the past.

Edward Plank *June 17, 2005*

(A) Fiscal year ends Sept. 30th.
(B) Basic earnings per share. Excludes acct'g gains/(losses): '89, $0.30; '99, $0.22; '00, ($0.27). Next earnings report due late July.
(C) Dividends historically paid mid-January, April, July, October. ■ Dividend reinvestment plan available.
(D) Includes deferred charges. At 9/30/04: $74.0 mill., $1.96/sh.
(E) In millions.
(F) Earnings don't sum due to change in shares outstanding.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	80

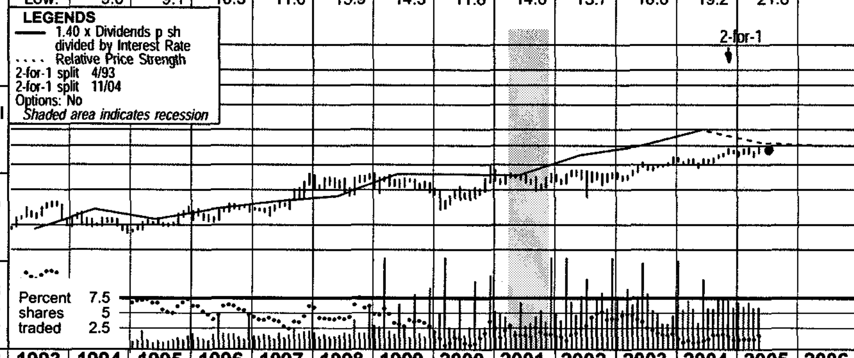
PIEDMONT NAT'L. NYSE-PNY

RECENT PRICE **23.71** | P/E RATIO **18.2** (Trailing: 20.9; Median: 16.0) | RELATIVE P/E RATIO **0.99** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS **5** Lowered 2/11/05
SAFETY **2** New 7/27/90
TECHNICAL **4** Lowered 6/17/05
BETA .75 (1.00 = Market)

High:	11.7	12.4	12.9	18.2	18.1	18.3	19.7	19.0	19.0	22.0	24.3	25.0
Low:	9.0	9.1	10.3	11.0	13.9	14.3	11.8	14.6	13.7	16.6	19.2	21.8

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 4/93
2-for-1 split 11/04
Options: No
Shaded area indicates recession



Target Price Range 2008 | 2009 | 2010
80 / 60 / 50 / 40 / 30 / 25 / 20 / 15 / 10 / 7.5

2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+50%)	13%
Low	25	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	8	0	9	0	10	9	10	8	9
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	1	0	1	1	0	1

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	61	80	80
to Sell	52	58	58
Hld's(000)	30297	30343	30461

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	24.0	11.0
3 yr.	54.4	39.9
5 yr.	95.1	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
10.12	9.42	8.32	8.91	10.57	10.82	8.76	11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	*22.20*	*20.80*	Revenues per sh A	*24.10*
.96	.97	.78	1.07	1.14	1.13	1.25	1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	*2.30*	*2.50*	"Cash Flow" per sh	*3.15*
.61	.61	.44	.70	.73	.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	*1.25*	*1.30*	Earnings per sh B	*1.60*
.39	.42	.44	.46	.48	.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.86	*.92*	*.98*	Div'ds Decl'd per sh C■	*1.10*
1.56	1.62	1.37	1.41	1.58	1.95	1.72	1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	*1.35*	*1.40*	Cap'l Spending per sh	*1.45*
4.37	4.58	4.83	5.13	5.45	5.68	6.16	6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	*11.45*	*11.90*	Book Value per sh D	*13.75*
41.57	42.87	49.46	51.59	52.30	53.15	57.67	59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	*77.00*	*76.00*	Common Shs Outst'g E	*73.00*
10.3	11.3	16.3	12.3	15.4	15.7	13.8	13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.78	.84	1.04	.75	.91	1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.87	*Value Line*		Relative P/E Ratio	*1.25*
6.3%	6.0%	6.0%	5.3%	4.3%	4.8%	5.4%	4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 1/31/05
Total Debt $849.5 mill. Due in 5 Yrs $275.0 mill.
LT Debt $660.0 mill. LT Interest $33.0 mill.
(LT interest earned: 4.1x; total interest coverage: 3.9x)

Pension Assets-10/04 $125.1 mill.
Oblig. $149.7 mill.

Pfd Stock None

Common Stock 76,681,352 shs.
as of 3/1/05

MARKET CAP: $1.8 billion (Mid Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
505.2	685.1	775.5	765.3	686.5	830.4	1107.9	832.0	1220.8	1529.7	*1710*	*1580*	Revenues ($mill) A	*1760*
40.3	48.6	55.2	60.3	58.2	64.0	65.5	62.2	74.4	95.2	*95.0*	*100*	Net Profit ($mill)	*120*
38.7%	38.9%	39.1%	39.2%	39.7%	34.7%	34.6%	33.1%	34.8%	35.1%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
8.0%	7.1%	7.1%	7.9%	8.5%	7.7%	5.9%	7.5%	6.1%	6.2%	*5.6%*	*6.3%*	Net Profit Margin	*6.7%*
50.4%	50.3%	47.6%	44.7%	46.2%	46.1%	47.6%	43.9%	42.2%	43.6%	*43.0%*	*42.0%*	Long-Term Debt Ratio	*37.5%*
49.6%	49.7%	52.4%	55.3%	53.8%	53.9%	52.4%	56.1%	57.8%	56.4%	*57.0%*	*58.0%*	Common Equity Ratio	*62.5%*
716.0	777.1	800.8	829.3	914.7	978.4	1069.4	1051.6	1090.2	1514.9	*1540*	*1565*	Total Capital ($mill)	*1605*
801.3	862.0	941.7	990.6	1047.0	1072.0	1114.7	1158.5	1812.3	1849.8	*1900*	*1950*	Net Plant ($mill)	*2150*
7.5%	8.2%	8.9%	9.2%	8.1%	8.3%	7.9%	7.8%	8.6%	7.8%	*7.5%*	*8.0%*	Return on Total Cap'l	*9.0%*
11.4%	12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	*11.0%*	*11.0%*	Return on Shr. Equity	*12.0%*
11.4%	12.6%	13.1%	13.2%	11.8%	12.1%	11.7%	10.6%	11.8%	11.1%	*11.0%*	*11.0%*	Return on Com Equity	*12.0%*
2.7%	3.9%	4.6%	4.7%	3.3%	3.5%	3.0%	1.7%	3.1%	3.7%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
76%	69%	65%	65%	72%	71%	75%	83%	74%	66%	*75%*	*74%*	All Div'ds to Net Prof	*67%*

CURRENT POSITION ($MILL.)	2003	2004	1/31/05
Cash Assets	11.2	5.7	25.5
Other	296.4	329.5	538.8
Current Assets	307.6	335.2	564.3
Accts Payable	90.9	99.6	160.5
Debt Due	557.1	109.5	189.5
Other	77.2	97.1	134.1
Current Liab.	725.2	306.2	484.1
Fix. Chg. Cov.	288%	356%	378%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	5.5%	7.0%	*5.0%*
"Cash Flow"	6.5%	4.0%	*6.5%*
Earnings	4.5%	3.0%	*7.5%*
Dividends	5.5%	5.0%	*4.0%*
Book Value	6.0%	5.5%	*7.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2002	288.7	293.9	127.9	121.5	832.0
2003	493.5	407.8	140.1	179.4	1220.8
2004	618.8	482.4	214.7	213.8	1529.7
2005	680.6	*540*	*250*	*239.4*	*1710*
2006	*635*	*500*	*220*	*225*	*1580*

Fiscal Year Ends	EARNINGS PER SHARE A B F Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2002	.63	.64	d.14	d.18	.95
2003	.87	.47	d.15	d.08	1.11
2004	1.03	.54	d.11	d.21	1.27
2005	.93	*.54*	*d.11*	*d.11*	*1.25*
2006	*.98*	*.53*	*d.11*	*d.10*	*1.30*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.183	.193	.193	.193	.76
2002	.20	.20	.20	.20	.80
2003	.208	.208	.208	.208	.83
2004	.215	.215	.215	.215	.86
2006	.23	.23			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 960,000 customers in North Carolina, South Carolina, and Tennessee. 2004 revenue mix: residential (43%), commercial (25%), industrial (9%), other (23%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 53.3% of revenues. '04 depreciation rate: 3.3%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 2,155 employees, 16,433 shareholders of record. CEO & President: Thomas E. Skains. Incorporated: North Carolina. Address: 1915 Rexford Road, P.O. Box 33068 Charlotte, NC 28233. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas' fiscal second quarter (ended April 30th) earnings were likely in line with our expectations. Share net probably topped out at about $0.54, flat versus last year. For the whole of fiscal 2005, we estimate a slight dip in EPS. Higher gas prices continue to pose somewhat of a risk to our estimate, as they tend to increase gas carrying costs and uncollectibles from low-income customers. We believe Piedmont's customer growth rate will remain in the above average 3%-3.5% range, given the proliferation of new housing starts in the company's service territories.

Potential rate relief may prove our earnings target conservative. The company has filed a general rate case in North Carolina. As part of the filing, management will propose to consolidate all of its North Carolina operations under one tariff, one set of service regulations, and one rate structure. This will encompass almost 70% of the rate base. The filing seeks to implement the new rates by November. Separately, the governor of South Carolina signed natural gas rate stabilization legislation that essentially allows gas utilities in to file for annual rate adjustments.

Non-utility businesses are likely to comprise a greater portion of future earnings. Regulated operations continue to make up the lion's share of Piedmont's total income. And while management intends to remain focused on being a gas utility, unregulated activities, which include SouthStar Energy and the Pine Needle and Cardinal Pipeline joint ventures, should consistently contribute to the bottom line. We expect Piedmont to continue to pursue strategic investments (likely storage or pipeline assets), a strategy that has permitted the company to diversify its earnings stream. Management intends to grow this segment to at least 15% of total earnings.

Though untimely, this issue is suitable for income-oriented accounts. Piedmont's dividend yield remains an attraction, and we expect steady increases in payments going forward. Currently, the yield stands at 3.9%, roughly average for the LDC group. Furthermore, risk should be held to a minimum, considering the stock's above average Safety grade.

Edward Plank *June 17, 2005*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early August.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges At 10/31/04: $5.3 million, 7¢/share.
(E) In millions, adjusted for stock splits.
(F) Quarters may not add to total due to change in shares outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	80
Earnings Predictability	80

SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 28.70 | P/E RATIO 17.4 (Trailing: 17.6 / Median: 13.0) | RELATIVE P/E RATIO 0.95 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 4 Lowered 12/17/04

SAFETY 2 Lowered 1/4/91

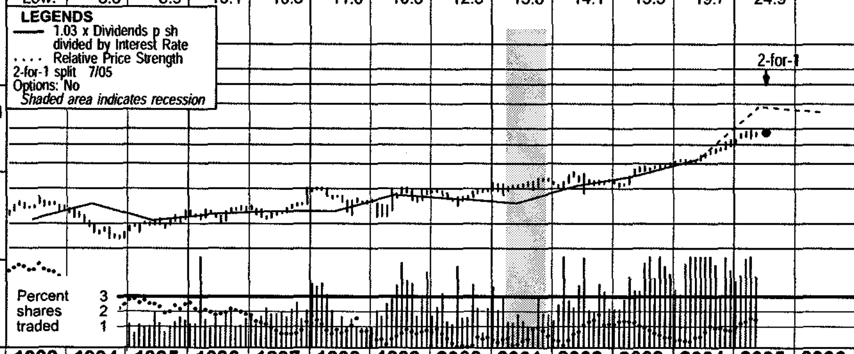
TECHNICAL 3 Raised 6/10/05

BETA .60 (1.00 = Market)

High:	12.0	11.8	12.3	15.3	15.4	15.4	15.1	17.0	18.3	20.3	26.5	29.7	
Low:	8.3	8.9	10.1	10.5	11.0	10.8	12.3	13.8	14.1	15.3	19.7	24.9	

Target Price Range 2008 | 2009 | 2010

LEGENDS
— 1.03 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded area indicates recession



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+20%)	8%
Low	25	(-15%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	1	3

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	39	46	31
to Sell	35	35	51
Hld's(000)	12466	12938	12752

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	39.8	11.0
3 yr.	82.3	39.9
5 yr.	160.4	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
15.27	14.40	15.10	16.67	17.03	17.45	16.50	16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	*30.30*	*31.50*	Revenues per sh	*35.00*
1.50	1.34	1.37	1.56	1.54	1.35	1.65	1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	*2.60*	*2.75*	"Cash Flow" per sh	*3.10*
.83	.67	.64	.81	.78	.61	.83	.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	*1.65*	*1.75*	Earnings per sh A	*2.00*
.68	.70	.71	.71	.72	.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	*.85*	*.90*	Div'ds Decl'd per sh B ■	*1.15*
2.27	2.11	2.17	1.69	1.87	1.93	2.08	2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	*2.25*	*2.65*	Cap'l Spending per sh	*3.10*
6.74	6.79	6.77	6.95	7.17	7.23	7.34	8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	*13.25*	*13.75*	Book Value per sh C	*15.80*
16.96	18.06	18.48	19.00	19.61	21.43	21.44	21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	*28.40*	*28.60*	Common Shs Outst'g D	*30.00*
11.9	13.6	14.5	13.2	15.8	16.1	12.2	13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.90	1.01	.93	.80	.93	1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.75	*Value Line*		Relative P/E Ratio	*.95*
6.9%	7.7%	7.6%	6.6%	5.9%	7.4%	7.2%	6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 3/31/05
Total Debt $353.8 mill. Due in 5 Yrs $19.5 mill.
LT Debt $321.4 mill. LT Interest $20.0 mill.
(Total interest coverage: 5.8x)

Pension Assets-12/04 $107.5 mill. Oblig. $100.5 mill.

Pfd Stock $1.7 mill. Pfd Div'd $.1 mill.
16,904 Series B shs. 8% cum. ($100 par) callable 106.7

Common Stock 27,953,000 common shs.
Adjusted for 2 for 1 split on June 10th.

MARKET CAP: $800 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
353.8	355.5	348.6	450.2	392.5	515.9	837.3	505.1	696.8	819.1	*860*	*900*	Revenues ($mill)	*1050*
17.8	18.5	18.4	13.8	22.0	24.7	26.8	29.4	34.6	43.0	*47.0*	*49.0*	Net Profit ($mill)	*60.0*
34.4%	35.5%	36.8%	46.2%	42.8%	43.1%	42.2%	41.4%	40.6%	40.9%	*40.5%*	*40.5%*	Income Tax Rate	*40.5%*
5.0%	5.2%	5.3%	3.1%	5.6%	4.8%	3.2%	5.8%	5.0%	5.2%	*5.4%*	*5.5%*	Net Profit Margin	*5.6%*
51.4%	46.1%	54.6%	57.3%	53.8%	54.1%	57.0%	53.6%	50.8%	48.7%	*49.0%*	*49.0%*	Long-Term Debt Ratio	*49.0%*
47.9%	53.2%	35.8%	33.5%	37.0%	37.6%	35.9%	46.1%	49.0%	51.0%	*51.0%*	*51.0%*	Common Equity Ratio	*51.0%*
328.4	324.8	387.1	401.1	405.9	443.5	516.2	512.5	608.4	675.0	*725*	*770*	Total Capital ($mill)	*925*
422.7	423.9	456.5	504.3	533.3	562.2	607.0	666.6	748.3	799.9	*825*	*875*	Net Plant ($mill)	*1050*
7.8%	7.9%	6.7%	5.3%	7.4%	7.4%	6.9%	7.6%	7.3%	7.9%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.2%	10.5%	10.5%	8.1%	11.7%	12.1%	12.1%	12.4%	11.5%	12.4%	*13.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
11.2%	10.6%	13.3%	10.3%	14.6%	14.8%	12.8%	12.5%	11.6%	12.5%	*13.0%*	*12.5%*	Return on Com Equity	*12.5%*
1.4%	1.6%	2.1%	NMF	4.2%	4.8%	3.5%	4.7%	5.0%	5.9%	*6.5%*	*6.0%*	Retained to Com Eq	*6.0%*
88%	85%	84%	112%	72%	67%	76%	62%	57%	52%	*51%*	*53%*	All Div'ds to Net Prof	*52%*

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	4.4	5.3	14.2
Other	261.4	278.6	129.9
Current Assets	265.8	283.9	144.1
Accts Payable	80.3	118.8	59.8
Debt Due	118.1	97.6	12.3
Other	70.1	68.9	65.0
Current Liab.	268.5	285.3	137.1
Fix. Chg. Cov.	378%	427%	446%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	7.0%	*5.5%*
"Cash Flow"	4.5%	7.0%	*5.5%*
Earnings	6.5%	10.5%	*5.5%*
Dividends	1.0%	1.5%	*5.0%*
Book Value	4.5%	11.5%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	177.0	84.2	69.1	174.8	505.1
2003	279.9	106.2	90.1	220.6	696.8
2004	307.6	136.5	129.5	245.5	819.1
2005	328.5	*145*	*140*	*246.5*	*860*
2006	*335*	*150*	*145*	*270*	*900*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	.83	.03	d.14	.50	1.22
2003	.92	.08	d.07	.44	1.37
2004	.91	.15	.02	.50	1.58
2005	.96	*.15*	*.02*	*.52*	*1.65*
2006	*.99*	*.18*	*.03*	*.55*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.182	.185	.185	.185	.74
2002	.185	.188	.188	.38	.94
2003	.193	.193	.193	.395	.78
2004	.202	.202	.202	.212	.82
2005	.212	.212			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 314,000 customers in New Jersey's southern counties, which cover 2,500 square miles and include Atlantic City. Principal suppliers include Transcontinental Gas Pipeline and Columbia Gas Pipeline. Gas revenue mix '04: residential, 31%; commercial and industrial, 10%; transportion, including off-system sales and gas marketing, 54%; off-system, 4%; cogeneration & power generation, 1%. Has 643 employees. Offs./dirs. cntrl. 1.4% of com. shares; Dimensional Fund Advisors, 7.4% (3/05 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Rte. 54, Folsom, NJ 08037. Telephone: 609-561-9000. Web: www.sjindustries.com.

In the near term, South Jersey Industries is apt to produce strong results. On the nonutility side of the business, it has signed contracts to construct a landfill-gas generation facility in Warren County, N.J. This plant, which will be a sister to SJI's newly operational Egg Harbor facility, is scheduled to come on line by early 2006. In addition, the 2006 planned expansion of the Borgata Hotel's onsite energy production facility appears to be on track. We believe that these projects will total 4% to 5% of total revenue by 2007.

On the regulated utility side of the business, the company has filed for a rate increase. Utility operations comprise 60% of total revenue. The approval would provide welcome relief from the 12% increase in wholesale gas prices that has occurred over the previous 12 months. Considering this precipitous rise in prices, we feel that some measure of increase will be awarded. Nonetheless, as the approval of increases is difficult to predict, we have not adjusted our models to reflect it.

Nonutility initiatives should be the main driver of earnings growth into 2008-2010. The Borgata Hotel has plans to add a new building in 2007. This project would necessitate an additional expansion of the Borgata's onsite energy production facility operated under a 20-year contract by SJI's subsidiary, Marina Energy.

South Jersey's dividend yield is below average in the natural das distribution space. This low yield is predominately the result of SJI being a small, fast growing utility. Indeed, stronger earnings growth has driven up the share price 17% in six months. As a result, the company's dividend yield has dwindled. As such, income investors may choose to look elsewhere but...

Management has made a commitment to increase dividends between 3% and 6% per annum. Given our estimates, we feel that future increases will remain near the upper end of this range. Although a position in SJI may be well suited to investors who are willing to sacrifice some yield for capital appreciation potential, it may also interest yield-investors searching for a growing income stream.

Note: The June 10th 2-for-1 stock split is reflected in our presentation.

Edward C. Muztafago *June 17, 2005*

(A) Based on avg. shs. Excl. nonrecur. gain: '01, $0.13. Excl gain (losses) from discont. ops.: '96, $1.14; '97, ($0.24); '98, ($0.26); '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09). Excl. gain due to acct'g change: '93, $0.04; '01, $0.14. Next egs. report due late July.
(B) Dividends paid early Jan., Apr., Jul., and Oct. ■ Div. reinvest. plan avail. (2% disc.).
(C) Incl. regulatory assets: in '04, $5.26 per shr.
(D) In mill.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	85

WGL HOLDINGS NYSE-WGL

RECENT PRICE 32.72 | P/E RATIO 16.0 (Trailing: 15.9 Median: 14.0) | RELATIVE P/E RATIO 0.87 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS 4 Raised 2/11/05

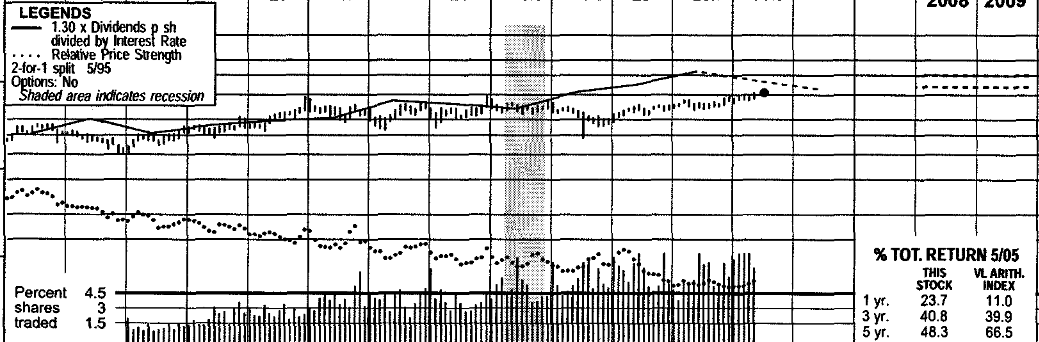
SAFETY 1 Raised 4/2/93

TECHNICAL 3 Lowered 9/24/04

BETA .75 (1.00 = Market)

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	21.3	22.4	25.0	31.4	30.8	29.4	31.5	30.5	29.5	28.8	31.4	33.5	
Low:	16.0	16.1	19.1	20.9	23.1	21.0	21.8	25.3	19.3	23.2	26.7	28.8	

Target Price Range 2008 | 2009 | 2010



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+20%)	9%
Low	35	(+5%)	5%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	68	86	92
to Sell	51	60	62
Hld's(000)	23834	24821	26169

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	23.7	11.0
3 yr.	40.8	39.9
5 yr.	48.3	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
19.52	18.75	17.50	18.37	21.55	21.69	19.30	22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	45.15	46.90	Revenues per sh A	54.40
2.03	2.17	2.04	2.17	2.25	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.90	4.05	"Cash Flow" per sh	4.85
1.22	1.26	1.14	1.27	1.31	1.42	1.45	1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.00	2.10	Earnings per sh B	2.60
.97	1.01	1.05	1.07	1.09	1.11	1.12	1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.33	1.34	Div'ds Decl'd per sh C ■	1.40
3.00	2.38	2.05	2.17	2.43	2.84	2.63	2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.70	2.75	Cap'l Spending per sh	2.95
9.86	10.17	9.63	10.66	11.04	11.51	11.95	12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.60	18.40	Book Value per sh D	20.40
38.70	39.23	39.89	40.62	41.50	42.19	42.93	43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.70	48.70	Common Shs Outst'g E	48.70
10.6	11.7	12.8	13.6	15.6	14.0	12.7	11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	Bold figures are		Avg Ann'l P/E Ratio	14.0
.80	.87	.82	.82	.92	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	Value Line		Relative P/E Ratio	.95
7.5%	6.9%	7.2%	6.2%	5.3%	5.6%	6.1%	5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	estimates		Avg Ann'l Div'd Yield	3.7%

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
828.7	969.8	1055.8	1040.6	972.1	1031.1	1446.5	1584.8	2064.2	2089.6	2200	2285	Revenues ($mill) A	2650
62.9	81.6	82.0	68.6	68.8	84.6	89.9	55.7	112.3	98.0	100	105	Net Profit ($mill)	125
37.4%	37.7%	36.9%	35.6%	36.0%	36.1%	39.6%	34.0%	38.0%	38.2%	37.0%	37.0%	Income Tax Rate	37.0%
7.6%	8.4%	7.8%	6.6%	7.1%	8.2%	6.2%	3.5%	5.4%	4.7%	4.5%	4.6%	Net Profit Margin	4.7%
37.8%	37.6%	41.1%	40.3%	41.5%	43.1%	41.7%	45.7%	43.8%	40.9%	38.5%	37.0%	Long-Term Debt Ratio	34.5%
58.9%	59.4%	56.2%	57.1%	56.1%	54.8%	56.3%	52.4%	54.3%	57.2%	60.0%	61.5%	Common Equity Ratio	63.5%
870.6	941.1	1049.0	1064.8	1218.5	1299.2	1400.8	1462.5	1454.9	1443.6	1485	1505	Total Capital ($mill)	1615
1056.1	1130.6	1217.1	1319.5	1402.7	1460.3	1519.7	1606.8	1874.9	1915.6	1950	2085	Net Plant ($mill)	2510
8.7%	10.1%	9.3%	8.0%	7.1%	7.9%	7.9%	5.3%	9.1%	8.2%	6.5%	7.0%	Return on Total Cap'l	8.0%
11.6%	13.9%	13.3%	10.8%	9.7%	11.4%	11.0%	7.0%	13.7%	11.5%	11.0%	11.0%	Return on Shr. Equity	12.0%
12.0%	14.4%	13.7%	11.1%	9.9%	11.7%	11.2%	7.2%	14.0%	11.7%	11.0%	11.0%	Return on Com Equity	12.5%
2.8%	5.6%	5.1%	2.5%	1.8%	3.7%	3.8%	NMF	6.2%	4.1%	3.5%	4.0%	Retained to Com Eq	5.5%
77%	62%	63%	78%	82%	69%	67%	112%	56%	65%	67%	65%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 3/31/05
Total Debt $614.3 mill. **Due in 5 Yrs** $315.0 mill.
LT Debt $523.7 mill. **LT Interest** $40.0 mill.
(LT interest earned: 5.0x; total interest coverage: 4.8x)

Pension Assets-9/04 $683.1 mill. **Oblig.** $655.8 mill.
Preferred Stock $28.2 mill. **Pfd Div'd** $1.3 mill.

Common Stock 48,692,876 shs. as of 4/30/05

MARKET CAP: $1.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2003	2004	3/31/05
Cash Assets	4.5	6.6	72.2
Other	404.4	426.3	559.6
Current Assets	408.9	432.9	631.8
Accts Payable	142.7	179.0	208.0
Debt Due	178.9	156.3	90.6
Other	64.5	77.6	273.6
Current Liab.	386.1	412.9	572.2
Fix. Chg. Cov.	487%	449%	460%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	6.5%	11.5%	5.5%
"Cash Flow"	4.5%	4.0%	5.5%
Earnings	3.0%	2.0%	6.5%
Dividends	1.5%	1.5%	1.5%
Book Value	4.0%	3.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	417.1	564.8	314.2	288.7	1584.8
2003	560.0	851.1	373.2	279.9	2064.2
2004	585.3	862.2	356.9	285.2	2089.6
2005	624.1	931.5	369	275.4	2200
2006	650	935	390	310	2285

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2002	.66	1.09	d.14	d.47	1.14
2003	1.10	1.61	d.05	d.36	2.30
2004	.81	1.62	d.08	d.37	1.98
2005	.88	1.63	d.15	d.36	2.00
2006	.93	1.58	d.08	d.33	2.10

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.31	.315	.315	.315	1.26
2002	.315	.318	.318	.318	1.27
2003	.318	.32	.32	.32	1.28
2004	.32	.325	.325	.325	1.30
2005	.325	.333			

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA. and MD. to resident'l and comm'l users (1,006,227 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Has 1,914 employees. Off./dir. own less than 1% of the common stock (1/05 proxy). Chairman & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Address: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings' March quarter was well ahead of our previous expectation. This was generated by temperatures that were colder than normal, along with strong results in the company's retail energy-marketing business. Too, over the 2008–2010 period, we expect the company's nonregulated segment to represent a greater proportion of total earnings (currently about 7%).

Net income from its nonregulated segment is doing well. The retail segment reported net income of $5.8 million this past quarter versus a net loss of $183,000 in the year-ago period. This reflects higher margins in the sale of natural gas. Moreover, losses in the heating, ventilating, and air-conditioning unit have narrowed so far versus last year, and management expects this unit to break even in 2005.

WGL will be replacing all of its mechanical couplings over 100 square miles in Prince George's County, Maryland. This is a result of a jump in the number of gas leaks. The company intends to fix the leaks within the next six months and replace all couplings in the system by December of 2007. This project is likely to cost $87 million, which does not include paving costs that may total an additional $50 million. By replacing these couplings rather than repairing them, the company can treat these costs as capital expenditures. WGL has filed with Maryland regulators for rate relief, and we expect the company to recover most, if not all, of the charges associated with this project.

The company has announced plans to construct a $60 million liquefied natural gas facility. This would have a capacity of one billion cubic feet of gas and be located in Chillum, Maryland. This location was selected because it will enhance pressure on the eastern portion of the system. This plant should allow WGL to purchase and store gas when demand and prices are lower, and deliver the gas to customers during peak times. It is scheduled to be in service for the 2008–2009 winter.

This stock is untimely, but holds appeal for income-oriented investors. The company has increased its dividend for 29 consecutive years, and offers a solid yield at 4.1%.

Evan I. Blatter *June 17, 2005*

(A) Beginning 1989, fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢).
Next earnings report due late July.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '04: $156.5 million, $3.22/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	60

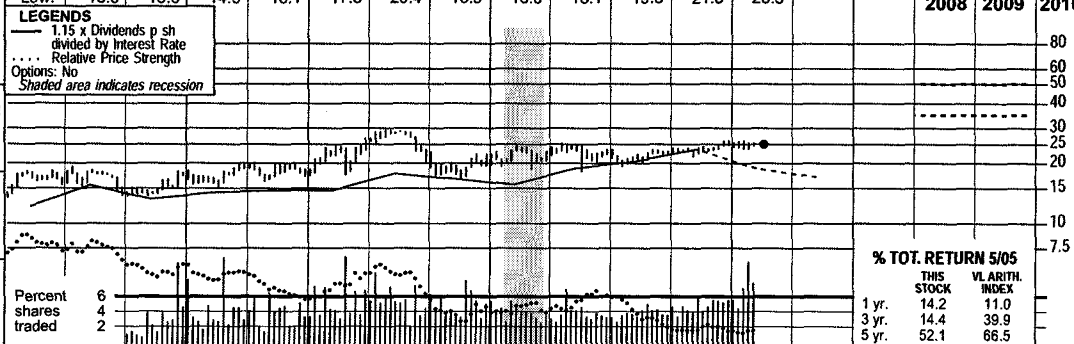
ATTACHMENT C

SOUTHWEST GAS NYSE-SWX

RECENT PRICE **24.97** | P/E RATIO **20.0** (Trailing: 18.4, Median: 20.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **3.3%** | **VALUE LINE**

TIMELINESS 4 Lowered 5/6/05
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 6/10/05
BETA .75 (1.00 = Market)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005
High:	19.4	18.4	19.9	20.3	26.9	29.5	23.0	24.7	25.3	23.6	26.2	26.1
Low:	13.8	13.6	14.9	16.1	17.3	20.4	16.9	18.6	18.1	19.3	21.5	23.5



2008-10 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+100%)	21%
Low	35	(+40%)	11%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	1	1	0	2	2	0	0	1
Options	1	0	0	1	5	1	0	0	1
to Sell	1	0	2	1	6	2	0	0	4

Institutional Decisions

	3Q2004	4Q2004	1Q2005
to Buy	73	65	66
to Sell	31	36	45
Hld's(000)	21055	21987	22540

% TOT. RETURN 5/05

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.2	11.0
3 yr.	14.4	39.9
5 yr.	52.1	66.5

1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	© VALUE LINE PUB., INC.	08-10
25.71	25.90	24.99	25.93	25.68	28.16	23.03	24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	**42.65**	**43.55**	Revenues per sh A	**44.50**
4.10	3.96	1.53	3.34	3.24	5.09	2.65	3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	**5.30**	**5.85**	"Cash Flow" per sh	**6.90**
2.15	1.81	d.76	.81	.63	1.22	.10	.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	**1.25**	**1.60**	Earnings per sh A B	**2.35**
1.39	1.40	.88	.70	.74	.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	**.82**	**.82**	Div'ds Decl'd per sh C■	**.82**
5.67	5.06	3.76	5.02	5.43	6.64	6.79	8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	**6.35**	**6.60**	Cap'l Spending per sh	**6.50**
17.30	17.63	15.88	15.99	15.96	16.38	14.55	14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	**20.15**	**20.80**	Book Value per sh	**23.55**
19.32	20.04	20.60	20.60	21.00	21.28	24.47	26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	**37.75**	**38.00**	Common Shs Outst'g D	**40.00**
8.5	8.7	--	16.6	26.5	14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	*Bold figures are*	*Value Line*	Avg Ann'l P/E Ratio	**18.0**
.64	.65	--	1.01	1.57	.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	*estimates*		Relative P/E Ratio	**1.20**
7.6%	8.9%	7.0%	5.2%	4.4%	4.7%	5.4%	4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%			Avg Ann'l Div'd Yield	**1.9%**

CAPITAL STRUCTURE as of 3/31/05

Total Debt $1302.4 mill. Due in 5 Yrs $505.0 mill.
LT Debt $1262.1 mill. LT Interest $80.0 mill.
(Total interest coverage: 1.9x)

Pension Assets-12/04 $242.2 mill.
Oblig. $319.4 mill.

Pfd Stock None

Common Stock 37,617,317 shs.
(as of 5/3/05)

MARKET CAP: $950 million (Small Cap)

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006		08-10
563.5	644.1	732.0	917.3	936.9	1034.1	1396.7	1320.9	1231.0	1477.1	**1610**	**1655**	Revenues ($mill) A	**1780**
2.7	6.6	20.8	47.5	39.3	38.3	37.2	38.6	38.5	58.9	**45.0**	**60.0**	Net Profit ($mill)	**95.0**
24.0%	37.1%	29.2%	43.4%	35.5%	26.2%	34.5%	32.8%	30.5%	34.8%	**35.0%**	**35.0%**	Income Tax Rate	**31.0%**
.5%	1.0%	2.8%	5.2%	4.2%	3.7%	2.7%	2.9%	3.1%	4.0%	**2.9%**	**3.7%**	Net Profit Margin	**5.3%**
65.2%	60.2%	63.6%	60.2%	60.3%	60.2%	56.2%	62.5%	66.0%	64.2%	**62.0%**	**60.5%**	Long-Term Debt Ratio	**51.5%**
34.8%	34.4%	31.5%	35.3%	35.5%	35.8%	39.6%	34.1%	34.0%	35.8%	**38.0%**	**39.5%**	Common Equity Ratio	**48.5%**
1024.0	1104.8	1224.7	1349.3	1424.7	1489.9	1417.6	1748.3	1851.6	1968.6	**2010**	**1990**	Total Capital ($mill) A	**1940**
1137.8	1278.5	1360.3	1459.4	1581.1	1686.1	1825.6	1979.5	2175.7	2336.0	**2535**	**2720**	Net Plant ($mill)	**3295**
2.7%	2.8%	3.9%	5.8%	4.8%	4.6%	5.1%	4.3%	4.2%	5.0%	**4.0%**	**5.0%**	Return on Total Cap'l	**7.0%**
.7%	1.5%	4.7%	8.9%	7.0%	6.5%	6.0%	5.9%	6.1%	8.3%	**6.0%**	**7.5%**	Return on Shr. Equity	**10.0%**
.7%	1.7%	5.4%	10.0%	7.8%	7.2%	6.6%	6.5%	6.1%	8.3%	**6.0%**	**7.5%**	Return on Com Equity	**10.0%**
NMF	NMF	NMF	5.0%	2.8%	2.4%	1.9%	1.9%	1.7%	4.3%	**2.0%**	**3.5%**	Retained to Com Eq	**6.5%**
NMF	NMF	107%	50%	64%	67%	71%	70%	72%	49%	**69%**	**52%**	All Div'ds to Net Prof	**35%**

CURRENT POSITION ($MILL.)

	2003	2004	3/31/05
Cash Assets	17.2	13.6	16.7
Other	263.9	418.4	314.5
Current Assets	281.1	432.0	331.2
Accts Payable	110.1	165.9	103.1
Debt Due	58.4	129.8	40.3
Other	141.9	187.3	188.5
Current Liab.	310.4	483.0	331.9
Fix. Chg. Cov.	182%	166%	183%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '02-'04 to '08-'10
Revenues	4.0%	6.0%	3.5%
"Cash Flow"	3.0%	4.5%	6.0%
Earnings	4.0%	1.5%	10.5%
Dividends	1.0%	--	1.5%
Book Value	1.5%	4.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	499.5	261.1	223.9	336.4	1320.9
2003	403.3	255.8	220.2	351.7	1231.0
2004	473.4	278.7	264.5	460.5	1477.1
2005	542.9	*315*	*295*	*457.1*	*1610*
2006	*560*	*330*	*310*	*455*	*1655*

Cal-endar	EARNINGS PER SHARE B E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2002	1.14	d.35	d.49	.86	1.16
2003	.76	d.12	d.51	1.00	1.13
2004	1.18	d.24	d.51	1.23	1.66
2005	.88	*d.23*	*d.50*	*1.10*	*1.25*
2006	*1.05*	*d.20*	*d.45*	*1.20*	*1.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2001	.205	.205	.205	.205	.82
2002	.205	.205	.205	.205	.82
2003	.205	.205	.205	.205	.82
2004	.205	.205	.205	.205	.82
2005	.205	.205			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approx. 1.6 million customers in sections of Arizona, Nevada, and California. '04 margin mix: resid. and small commercial, 83%; large commercial and industrial, 4%; transportation, 13%. Annual volume: 2.2 billion therms. Principal suppliers: El Paso Natural Gas Co. and Northwest Pipeline Corp. Acquired gas utility assets from Arizona Public Service in 1984. Sold PriMerit Bank (acq. in '86) in 7/96. Has about 2,550 employees, 22,990 shareholders. Officers & Directors own 1.8% of common (6/04 Proxy). Chairman.: Thomas Y. Hartley. CEO: Jeffrey W. Shaw. Incorporated: CA. Address: 5241 Spring Mountain Rd., P.O. Box 98510, Las Vegas, NV 89193-8510. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas had a much weaker-than-expected first-quarter. Share net of $0.88 was significantly below our estimate of $1.23. The company suffered from warmer weather in its service territories, particularly in its largest operating area, Arizona. Results remain sensitive to temperature fluctuations, given the absence of a weather-normalization policy. This, coupled with higher operating costs, which increased 6% over last year's comparable period, crimped the bottom line. Southwest's operating leverage is slim given the exorbitant maintenance costs implicit in supporting its higher-than-average customer growth rate, which stands at around 5% annually.

The company is awaiting a rate-case decision in Arizona, which would mitigate the impact of weather on earnings and allow the company to recover its higher costs—all of which should benefit earnings going forward. Importantly, without the change in rate design, we think that Southwest's return on equity will continue to lag that of its peers. As a result of the weak first quarter, we have lowered our 2005 earnings estimate by $0.45 a share, to $1.25. Notwithstanding a rate hike, the company will need more favorable temperatures over the balance of the year to generate meaningful bottom-line growth, in our view.

During the last twelve months, Southwest added a record 82,000 customers. Typically, this pace of customer growth, while impressive, has been a doubled-edged sword for the company, given the implicit costs associated with such rapid expansion.

Southwest shares are not a standout. The company's balance sheet remains fairly highly leveraged, which doesn't augur well as interest rates ratchet up. Plus, in addition to seasonal losses, earnings have faltered dramatically for the reasons outlined above. As such, the current valuation reflects the difficulty of translating customer growth into earnings. Furthermore, as an income vehicle, Southwest shares are unappealing, since the yield is below average for the group and dividend payments have not expanded in almost a decade. Investors may want to look elsewhere until earning stabilize.

Edward Plank *June 17, 2005*

(A) Incl. income for PriMerit Bank on the equity basis through 1994.
(B) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢). Incl. asset writedown: '86, 9¢; '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Next egs. report due late July.
(C) Dividends historically paid early March, June, September, December.
■ Div'd reinvest. plan avail. (D) In millions.
(E) Quarters may not sum due to change in shares outstanding.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	60
Earnings Predictability	65

SOUTHWEST GAS CORPORATION

DOCKET NO. G-01551A-04-0876

TABLE OF CONTENTS TO SCHEDULES WAR

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
COST OF CAPITAL SUMMARY

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 1

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	LONG-TERM DEBT	53.00%	7.49%	3.97%
2	PREFERRED EQUITY	5.00%	8.20%	0.41%
3	COMMON EQUITY	42.00%	10.15%	4.26%
4	TOTAL CAPITALIZATION	100.00%		8.64%
5	COST OF CAPITAL			

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) ÷ COLUMN (C), LINE 4
COLUMN (E): TESTIMONY, WAR
COLUMN (F): COLUMN (D) x COLUMN (E)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DCF COST OF EQUITY CAPITAL

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	ATG	AGL RESOURCES, INC.	3.44%	+	6.22%	=	9.66%
2	CGC	CASCADE NATURAL GAS CORPORATION	4.86%	+	4.29%	=	9.15%
3	KSE	KEYSPAN CORP.	4.58%	+	4.49%	=	9.06%
4	LG	LACLEDE GROUP, INC.	4.55%	+	3.41%	=	7.96%
5	GAS	NICOR, INC.	4.66%	+	2.91%	=	7.57%
6	NWN	NORTHWEST NATURAL GAS CO.	3.53%	+	5.36%	=	8.89%
7	PGL	PEOPLES ENERGY CORPORATION	5.11%	+	3.73%	=	8.84%
8	PNY	PIEDMONT NATURAL GAS COMPANY	3.83%	+	4.14%	=	7.97%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	2.90%	+	7.21%	=	10.11%
10	WGL	WGL HOLDINGS, INC.	4.07%	+	5.86%	=	9.93%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						8.91%

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND YIELD CALCULATION

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 3

LINE NO.	STOCK SYMBOL	COMPANY	(A) ESTIMATED DIVIDEND (PER SHARE)	÷	(B) AVERAGE STOCK PRICE (PER SHARE)	=	(C) DIVIDEND YIELD
1	ATG	AGL RESOURCES, INC.	$1.24	÷	$36.02	=	3.44%
2	CGC	CASCADE NATURAL GAS CORPORATION	0.96	÷	19.77	=	4.86%
3	KSE	KEYSPAN CORP.	1.82	÷	39.75	=	4.58%
4	LG	LACLEDE GROUP, INC.	1.38	÷	30.36	=	4.55%
5	GAS	NICOR, INC.	1.86	÷	39.94	=	4.66%
6	NWN	NORTHWEST NATURAL GAS CO.	1.30	÷	36.85	=	3.53%
7	PGL	PEOPLES ENERGY CORPORATION	2.18	÷	42.65	=	5.11%
8	PNY	PIEDMONT NATURAL GAS COMPANY	0.92	÷	24.03	=	3.83%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	0.85	÷	29.23	=	2.90%
10	WGL	WGL HOLDINGS, INC.	1.33	÷	32.73	=	4.07%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						4.15%

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - SUMMARY AND INDEX DATED 06/17/05.
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 05/09/05 TO 07/01/05 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	ATG	AGL RESOURCES, INC.	6.00%	+	0.22%	=	6.22%
2	CGC	CASCADE NATURAL GAS CORPORATION	4.00%	+	0.29%	=	4.29%
3	KSE	KEYSPAN CORP.	4.00%	+	0.49%	=	4.49%
4	LG	LACLEDE GROUP, INC.	3.00%	+	0.41%	=	3.41%
5	GAS	NICOR, INC.	2.75%	+	0.16%	=	2.91%
6	NWN	NORTHWEST NATURAL GAS CO.	5.00%	+	0.36%	=	5.36%
7	PGL	PEOPLES ENERGY CORPORATION	3.00%	+	0.73%	=	3.73%
8	PNY	PIEDMONT NATURAL GAS COMPANY	4.00%	+	0.14%	=	4.14%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	6.00%	+	1.21%	=	7.21%
10	WGL	WGL HOLDINGS, INC.	5.75%	+	0.11%	=	5.86%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						4.76%

<u>REFERENCES:</u>
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) ÷ 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	ATG	AGL RESOURCES, INC.	0.50%	x	{ [((1.89) + 1) ÷ 2] - 1 }	=	0.22%
2	CGC	CASCADE NATURAL GAS CORPORATIO	1.00%	x	{ [((1.59) + 1) ÷ 2] - 1 }	=	0.29%
3	KSE	KEYSPAN CORP.	2.00%	x	{ [((1.49) + 1) ÷ 2] - 1 }	=	0.49%
4	LG	LACLEDE GROUP, INC.	1.50%	x	{ [((1.55) + 1) ÷ 2] - 1 }	=	0.41%
5	GAS	NICOR, INC.	0.25%	x	{ [((2.31) + 1) ÷ 2] - 1 }	=	0.16%
6	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.72) + 1) ÷ 2] - 1 }	=	0.36%
7	PGL	PEOPLES ENERGY CORPORATION	1.75%	x	{ [((1.83) + 1) ÷ 2] - 1 }	=	0.73%
8	PNY	PIEDMONT NATURAL GAS COMPANY	0.25%	x	{ [((2.10) + 1) ÷ 2] - 1 }	=	0.14%
9	SJI	SOUTH JERSEY INDUSTIES, INC.	2.00%	x	{ [((2.21) + 1) ÷ 2] - 1 }	=	1.21%
10	WGL	WGL HOLDINGS, INC.	0.25%	x	{ [((1.86) + 1) ÷ 2] - 1 }	=	0.11%
11	LOCAL DISTRIBUTION COMPANY AVERAGE						

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY , 06/17/05

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	ATG	AGL RESOURCES, INC.	2000	0.1628		11.50%		1.87%	11.50	54.00	
2			2001	0.2800		12.30%		3.44%	12.19	55.10	
3			2002	0.4066		14.50%		5.90%	12.52	56.70	
4			2003	0.4663		14.00%		6.53%	14.66	64.50	
5			2004	0.4956		11.00%		5.45%	18.06	76.70	
6			GROWTH 2000 - 2004					4.64%	6.00%		9.17%
7			2005	0.4609		12.00%		5.53%		77.20	0.65%
8			2006	0.4708		12.00%		5.65%		77.50	0.52%
9			2008-10	0.5091		11.50%		5.85%	8.00%	78.00	0.34%
10											
11	CGC	CASCADE NATURAL GAS CORPORATION	2000	0.3094		12.90%		3.99%	10.79	11.05	
12			2001	0.3469		13.30%		4.61%	11.01	11.05	
13			2002	0.1504		10.90%		1.64%	10.34	11.05	
14			2003	-0.1034		8.60%		-0.89%	10.11	11.13	
15			2004	0.1933		11.20%		2.16%	10.52	11.27	
16			GROWTH 2000 - 2004					2.30%	-		0.49%
17			2005	-0.0105		7.50%		-0.08%		11.30	0.27%
18			2006	0.2320		9.00%		2.09%		11.30	0.13%
19			2008-10	0.3875		11.00%		4.26%	7.00%	12.00	1.26%
20											
21	KSE	KEYSPAN CORP.	2000	0.1524		10.00%		1.52%	20.65	136.36	
22			2001	-0.0349		8.20%		-0.29%	20.73	139.43	
23			2002	0.3527		13.30%		4.69%	20.67	142.42	
24			2003	0.3206		11.40%		3.65%	22.94	159.66	
25			2004	0.5265		15.60%		8.21%	24.22	160.82	
26			GROWTH 2000 - 2004					3.56%	1.50%		4.21%
27			2005	0.2375		9.00%		2.14%		170.00	5.71%
28			2006	0.2885		9.50%		2.74%		170.00	2.81%
29			2008-10	0.3846		10.50%		4.04%	5.00%	166.00	0.64%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	LG	LACLEDE GROUP, INC.	2000	0.0219		9.10%		0.20%	14.99	18.88	
2			2001	0.1677		10.50%		1.76%	15.26	18.88	
3			2002	-0.1356		7.80%		NMF	15.07	18.96	
4			2003	0.2637		11.60%		3.06%	15.65	19.11	
5			2004	0.2582		10.10%		2.61%	16.96	20.98	
6			GROWTH 2000 - 2004					1.91%	1.50%		2.67%
7			2005	0.2171		9.00%		1.95%		21.50	2.48%
8			2006	0.2923		9.00%		2.63%		21.50	1.23%
9			2008-10	0.3689		8.00%		2.95%	11.00%	21.50	0.49%
10											
11	GAS	NICOR, INC.	2000	0.4354		19.20%		8.36%	15.56	45.49	
12			2001	0.4153		18.70%		7.77%	16.39	44.40	
13			2002	0.3611		17.50%		6.32%	16.55	44.01	
14			2003	0.1185		12.30%		1.46%	17.13	44.04	
15			2004	0.1622		13.10%		2.12%	16.99	44.10	
16			GROWTH 2000 - 2004					5.21%	1.00%		-0.77%
17			2005	0.1143		12.50%		1.43%		44.20	0.23%
18			2006	0.1733		12.50%		2.17%		44.20	0.11%
19			2008-10	0.2078		13.50%		2.81%	2.00%	44.50	0.18%
20											
21	NWN	NORTHWEST NATURAL GAS CO.	2000	0.3073		10.00%		3.07%	17.93	25.23	
22			2001	0.3351		10.20%		3.42%	18.56	25.23	
23			2002	0.2222		8.50%		1.89%	18.88	25.59	
24			2003	0.2784		9.00%		2.51%	19.52	25.94	
25			2004	0.3011		8.90%		2.68%	20.64	27.55	
26			GROWTH 2000 - 2004					2.71%	3.50%		2.22%
27			2005	0.4217		10.50%		4.43%		27.75	0.73%
28			2006	0.4333		10.50%		4.55%		28.00	0.81%
29			2008-10	0.4444		10.50%		4.67%	4.50%	28.50	0.68%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	PGL	PEOPLES ENERGY CORPORATION	2000	0.2620		12.40%		3.25%	22.02	35.30	
2			2001	0.3544		13.90%		4.93%	22.76	35.40	
3			2002	0.2607		12.30%		3.21%	22.74	35.46	
4			2003	0.2613		12.30%		3.21%	23.11	36.69	
5			2004	0.0092		9.40%		0.09%	23.06	36.69	
6			GROWTH 2000 - 2004					2.94%	2.50%		0.97%
7			2005	0.1615		11.50%		1.86%		38.00	3.57%
8			2006	0.1852		11.50%		2.13%		38.00	1.77%
9			2008-10	0.2750		10.50%		2.89%	4.50%	35.00	-0.94%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2000	0.2871		12.10%		3.47%	8.26	63.83	
12			2001	0.2475		12.10%		3.00%	8.63	64.93	
13			2002	0.1579		10.60%		1.67%	8.91	66.18	
14			2003	0.2613		11.80%		3.08%	9.36	67.31	
15			2004	0.3228		11.10%		3.58%	11.15	76.67	
16			GROWTH 2000 - 2004					2.96%	5.50%		4.69%
17			2005	0.2640		11.00%		2.90%		77.00	0.43%
18			2006	0.2462		11.00%		2.71%		76.00	-0.44%
19			2008-10	0.3125		12.00%		3.75%	7.50%	73.00	-0.98%
20											
21	SJI	SOUTH JERSEY INDUSTIES, INC.	2000	0.3241		14.80%		4.80%	7.25	23.00	
22			2001	0.3565		14.80%		5.28%	7.81	23.72	
23			2002	0.3852		12.50%		4.82%	9.67	24.41	
24			2003	0.4307		11.60%		5.00%	11.26	26.46	
25			2004	0.4810		12.50%		6.01%	12.41	27.76	
26			GROWTH 2000 - 2004					5.18%	11.50%		4.81%
27			2005	0.4848		13.00%		6.30%		28.40	2.31%
28			2006	0.4857		12.50%		6.07%		28.60	1.50%
29			2008-10	0.4250		12.50%		5.31%	6.00%	30.00	1.56%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
DIVIDEND GROWTH COMPONENTS

LINE NO.	STOCK SYMBOL	COMPANY	OPERATING PERIOD	(A) RETENTION RATIO (b)	x	(B) RETURN ON BOOK EQUITY (r)	=	(C) DIVIDEND GROWTH (g)	(D) BOOK VALUE ($/SHARE)	(E) SHARES OUTST. (MILLIONS)	(F) SHARE GROWTH
1	WGL	WGL HOLDINGS, INC.	2000	0.3073		11.70%		3.59%	15.31	46.47	
2			2001	0.3298		11.70%		3.86%	16.24	48.54	
3			2002	-0.1140		7.20%		NMF	15.78	48.56	
4			2003	0.4435		14.00%		6.21%	16.25	48.63	
5			2004	0.3434		11.70%		4.02%	16.95	48.67	
6			GROWTH 2000 - 2004					4.42%	3.00%		1.16%
7			2005	0.3350		11.00%		3.69%		48.70	0.06%
8			2006	0.3619		11.00%		3.98%		48.70	0.03%
9			2008-10	0.4615		12.50%		5.77%	4.00%	48.70	0.01%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/17/05
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2000 - 2004

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
GROWTH RATE COMPARISON

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 6

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	DPS	BVPS	(D) VALUE LINE HISTORIC EPS	DPS	BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	DPS	BVPS
1	ATG	6.22%	6.00%	5.00%	3.50%	8.00%	11.00%	0.50%	6.00%	5.71%	15.30%	1.58%	11.95%
2	CGC	4.29%	4.10%	7.00%	0.50%	7.00%	1.00%	-	-	3.92%	-3.81%	0.00%	-0.63%
3	KSE	4.49%	9.40%	1.00%	2.00%	5.00%	21.00%	4.00%	1.50%	6.27%	15.83%	0.14%	4.07%
4	LG	3.41%	3.50%	6.00%	1.00%	11.00%	-0.50%	0.50%	1.50%	3.29%	7.36%	0.19%	3.13%
5	GAS	2.91%	6.30%	1.00%	1.50%	2.00%	-0.50%	4.50%	1.00%	2.26%	-6.78%	2.88%	2.22%
6	NWN	5.36%	5.80%	7.50%	2.50%	4.50%	3.00%	1.00%	3.50%	3.97%	0.96%	1.19%	3.58%
7	PGL	3.73%	6.30%	1.00%	1.50%	4.50%	2.00%	2.00%	2.50%	2.83%	-5.30%	1.94%	1.16%
8	PNY	4.14%	6.70%	7.50%	4.00%	7.50%	3.00%	5.00%	5.50%	5.60%	5.89%	4.54%	7.79%
9	SJI	7.21%	5.30%	5.50%	5.00%	6.00%	10.50%	1.50%	11.50%	6.47%	9.98%	2.95%	14.38%
10	WGL	5.86%	5.30%	6.50%	1.50%	4.00%	2.00%	1.50%	3.00%	3.40%	2.55%	1.19%	2.58%
11				4.80%	2.30%	5.95%	5.25%	2.28%	4.00%		4.20%	1.66%	5.02%
12	AVERAGES	4.76%	5.87%		4.35%			3.84%		4.37%		3.63%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1, 3, 5 AND 7
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM
- VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 06/17/05

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	3.04%	+ [	0.85	x (	10.40%	-	3.04%	)]	=	9.30%
2	CGC	k	=	3.04%	+ [	0.75	x (	10.40%	-	3.04%	)]	=	8.56%
3	KSE	k	=	3.04%	+ [	0.80	x (	10.40%	-	3.04%	)]	=	8.93%
4	LG	k	=	3.04%	+ [	0.75	x (	10.40%	-	3.04%	)]	=	8.56%
5	GAS	k	=	3.04%	+ [	1.10	x (	10.40%	-	3.04%	)]	=	11.14%
6	NWN	k	=	3.04%	+ [	0.70	x (	10.40%	-	3.04%	)]	=	8.19%
7	PGL	k	=	3.04%	+ [	0.80	x (	10.40%	-	3.04%	)]	=	8.93%
8	PNY	k	=	3.04%	+ [	0.75	x (	10.40%	-	3.04%	)]	=	8.56%
9	SJI	k	=	3.04%	+ [	0.60	x (	10.40%	-	3.04%	)]	=	7.45%
10	WGL	k	=	3.04%	+ [	0.75	x (	10.40%	-	3.04%	)]	=	8.56%
11	LDC AVERAGE					0.79							8.82%

REFERENCES:
COLUMN (A): GENERAL CAPITAL ASSET PRICING MODEL (CAPM) FORMULA

$k = r_f + [ß (r_m - r_f)]$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 06/10/05 THROUGH 07/15/05 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+ [	(A) ß	x (	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	ATG	k	=	3.04%	+ [	0.85	x (	12.40%	-	3.04%	)]	=	11.00%
2	CGC	k	=	3.04%	+ [	0.75	x (	12.40%	-	3.04%	)]	=	10.06%
3	KSE	k	=	3.04%	+ [	0.80	x (	12.40%	-	3.04%	)]	=	10.53%
4	LG	k	=	3.04%	+ [	0.75	x (	12.40%	-	3.04%	)]	=	10.06%
5	GAS	k	=	3.04%	+ [	1.10	x (	12.40%	-	3.04%	)]	=	13.34%
6	NWN	k	=	3.04%	+ [	0.70	x (	12.40%	-	3.04%	)]	=	9.59%
7	PGL	k	=	3.04%	+ [	0.80	x (	12.40%	-	3.04%	)]	=	10.53%
8	PNY	k	=	3.04%	+ [	0.75	x (	12.40%	-	3.04%	)]	=	10.06%
9	SJI	k	=	3.04%	+ [	0.60	x (	12.40%	-	3.04%	)]	=	8.65%
10	WGL	k	=	3.04%	+ [	0.75	x (	12.40%	-	3.04%	)]	=	10.06%
11	LDC AVERAGE					0.79							10.39%

REFERENCES:
COLUMN (A): GENERAL CAPITAL ASSET PRICING MODEL (CAPM) FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
r_f = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
r_m = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) A 6-WEEK AVERAGE OF THE 91-DAY T-BILL RATES THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 06/10/05 THROUGH 07/15/05 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE MARKET RATE PROXY USED WAS THE ARITHMETIC MEAN FOR S&P 500 RETURNS OVER THE 1926 - 2004 PERIOD. THE DATA WAS OBTAINED FROM IBBOTSON ASSOCIATES' STOCKS, BONDS, BILLS AND INFLATION: 2005 YEARBOOK.

LINE NO.	YEAR	(A) CHANGE IN CPI	(B) CHANGE IN GDP (1996 $)	(C) PRIME RATE	(D) FED. DISC. RATE	(E) FED. FUNDS RATE	(F) 91-DAY T-BILLS	(G) 30-YR T-BONDS	(H) A-RATED UTIL. BOND YIELD	(I) Baa-RATED UTIL. BOND YIELD
1	1990	5.40%	1.90%	10.01%	6.98%	8.10%	7.49%	8.61%	9.86%	10.06%
2	1991	4.21%	-0.20%	8.46%	5.45%	5.69%	5.38%	8.14%	9.36%	9.55%
3	1992	3.01%	3.30%	6.25%	3.25%	3.52%	3.43%	7.67%	8.69%	8.86%
4	1993	2.99%	2.70%	6.00%	3.00%	3.02%	3.00%	6.60%	7.59%	7.91%
5	1994	2.56%	4.00%	7.14%	3.60%	4.20%	4.25%	7.37%	8.31%	8.63%
6	1995	2.83%	2.50%	8.83%	5.21%	5.84%	5.49%	6.88%	7.89%	8.29%
7	1996	2.95%	3.70%	8.27%	5.02%	5.30%	5.01%	6.70%	7.75%	8.17%
8	1997	1.70%	4.50%	8.44%	5.00%	5.46%	5.06%	6.61%	7.60%	8.12%
9	1998	1.60%	4.20%	8.35%	4.92%	5.35%	4.78%	5.58%	7.04%	7.27%
10	1999	2.70%	4.50%	7.99%	4.62%	4.97%	4.64%	5.86%	7.62%	7.88%
11	2000	3.40%	3.70%	9.23%	5.73%	6.24%	5.82%	5.94%	8.24%	8.36%
12	2001	1.60%	0.80%	6.92%	3.41%	3.88%	3.38%	5.95%	7.59%	8.02%
13	2002	2.40%	1.90%	4.67%	1.17%	1.66%	1.60%	5.38%	7.41%	7.98%
14	2003	1.90%	3.00%	4.12%	2.03%	1.13%	1.01%	4.92%	6.18%	6.64%
15	2004	2.23%	4.40%	4.34%	2.35%	1.35%	1.37%	5.03%	5.77%	6.20%
16	CURRENT	2.80%	3.50%	6.25%	4.25%	3.25%	3.14%	4.32%	5.18%	5.56%

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 07/15/05
COLUMN (H) THROUGH (J): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2002 THROUGH 2004 THE VALUE LINE INVESTMENT SURVEY

SOUTHWEST GAS CORPORATION
TEST YEAR ENDED AUGUST 31, 2004
CAPITAL STRUCTURES OF PUBLICLY TRADED LDC's (IN MILLIONS)

DOCKET NO. G-01551A-04-0876
SCHEDULE WAR - 9

LINE NO.		ATG	PCT.	CGC	PCT.	KSE	PCT.	LG	PCT.
1	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%
2	LONG-TERM DEBT	1,957.0	58.6%	176.4	59.8%	4,418.7	53.0%	380.3	51.6%
3	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	19.7	0.2%	1.1	0.1%
4	COMMON EQUITY	1,385.0	41.4%	118.5	40.2%	3,894.7	46.7%	355.9	48.3%
5	TOTALS	$3,342.0	100%	$294.9	100%	$8,333.1	100%	$737.3	100%
6		GAS	PCT.	NWN	PCT.	PGL	PCT.	PNY	PCT.
7	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%	$0.0	0.0%
8	LONG-TERM DEBT	495.3	39.8%	568.5	54.0%	897.4	50.8%	660.0	43.6%
9	PREFERRED STOCK	1.6	0.1%	0.0	0.0%	0.0	0.0%	0.0	0.0%
10	COMMON EQUITY	749.1	60.1%	484.0	46.0%	870.1	49.2%	854.9	56.4%
11	TOTALS	$1,246.0	100%	$1,052.5	100%	$1,767.5	100%	$1,514.9	100%
12		SJI	PCT.	WGL	PCT.	**AVERAGE**	**PCT.**	SWX	PCT.
13	SHORT-TERM DEBT	$0.0	0.0%	$0.0	0.0%	**$0.0**	**0.0%**	$0.0	0.0%
14	LONG-TERM DEBT	328.9	48.7%	590.2	40.1%	**1,047.3**	**51.2%**	1,181.4	60.8%
15	PREFERRED STOCK	1.7	0.3%	28.1	1.9%	**5.2**	**0.3%**	100.0	5.1%
16	COMMON EQUITY	344.4	51.0%	853.4	58.0%	**991.0**	**48.5%**	663.0	34.1%
17	TOTALS	$675.0	100%	$1,471.7	100%	**$2,043.5**	**100%**	$1,944.4	100%

REFERENCE:
2004 SEC 10-K FILINGS
COMPANY WITNESS WOOD EXHIBIT NO._(TKW-1)